# Freehold
ROYALTY TRUST

2004 ANNUAL REPORT

# Freehold

ROYALTY TRUST

**Our royalty lands continue to be a distinguishing feature. We are one of the largest owners of mineral title lands in western Canada and the only energy trust with this kind of asset base. A royalty interest offers the benefit of sharing in production, without the responsibility for normal costs associated with oil and gas operations. Our high percentage of royalty income results in superior netbacks to our Unitholders.**

# WHO WE ARE

We are one of the largest holders of privately-held mineral rights in western Canada. Formed in 1996, we were among the first of the publicly-traded oil and gas trusts in Canada. Our Trust Units (FRU.UN) trade on the Toronto Stock Exchange.

# WHAT WE OWN

We own interests in more than one million gross acres of land and receive production income from 17,000 oil and gas wells. In 2004, our production averaged 5,588 barrels of oil equivalent per day.

# OUR GOAL

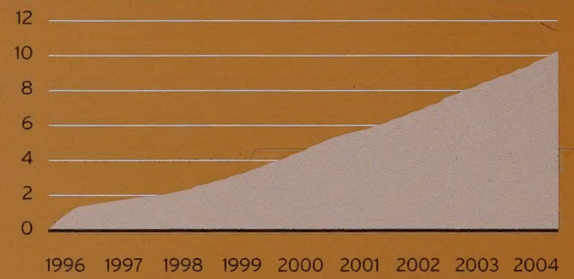
Our commitment to generate superior returns is our number one priority. Our goal is to extend cash distributions over the long term by actively managing our assets.

# OUR STRATEGY

We are focused on maximizing distributions and maintaining a conservative approach to debt management, while striving to acquire additional royalty interests to sustain the value of the Trust.

# INVESTMENT PERFORMANCE SINCE INCEPTION

**CUMULATIVE DISTRIBUTIONS DECLARED ($/unit)**

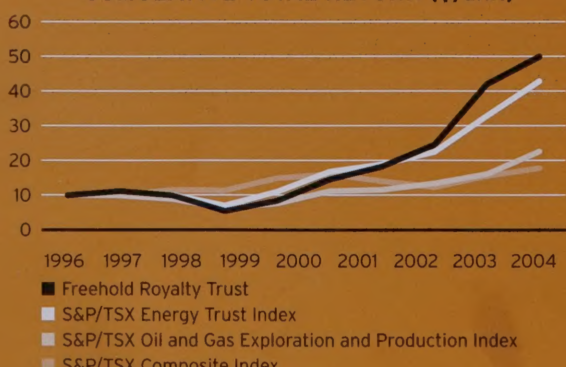



**Cash distributions declared from inception to December 31, 2004 total $10.28 per Trust Unit, more than the initial public offering price of $10. Excluding price appreciation, this represents a compound annual return of 13.3%.**

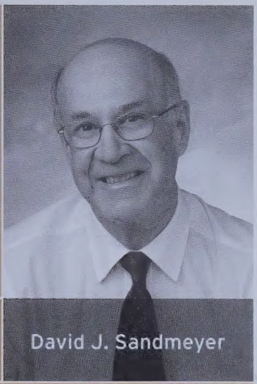
**TRUST UNIT CLOSING PRICE ($/unit)**


**On December 31, 2004, the closing price of our Trust Units on the TSX was $17.45. From the initial public offering price of $10 on November 25, 1996, the market value of our Trust Units has appreciated 75%.**

**CUMULATIVE TOTAL RETURN ($/unit)**




**Assuming reinvestment of all distributions received to December 31, 2004, a $10 investment at the time of the initial public offering has generated a total return of 400% and had a market value of $50 at December 31, 2004. Over this period, our Trust Units have outperformed all three comparative S&P/TSX benchmark indices.**




# PRESIDENT'S MESSAGE

**We reached a significant milestone in 2004, having returned the full initial public offering price of $10 per Trust Unit in cash distributions to Unitholders since inception. Our royalty assets, which are fundamental to our sustainability, continue to offer superior returns.**

In 2004, we celebrated our eighth anniversary. We are now in our ninth year of operation.

Our royalty assets, which are fundamental to our sustainability, continue to offer superior returns. Distributions since inception reached $10.28 per Trust Unit in 2004, returning the full initial public offering price. Assuming reinvestment of all distributions, an initial $10 investment generated a total return of 400% and had a market value of $50 at December 31, 2004. We also increased our regular distribution rate by 20% to 12 cents per month, beginning in September.

In last year's annual report, we estimated distributions of $1.40 per Trust Unit for 2004. This estimate was based on a number of assumptions, including production levels and commodity prices. Our average production came in slightly lower than estimated, while commodity prices far exceeded our expectations. Distributions reached a record $1.73 per Trust Unit ($1.71 on a taxation-year basis) as Unitholders directly benefited from record high cash flows. Our payout ratio was 85%, even as we maintained a healthy balance sheet and conservative debt-to-cash flow ratio of 0.4 to 1.

We continue to benefit from ongoing development by lessees on our royalty lands. These legacy assets, which stem from lands granted by King Charles II to the Hudson's Bay Company in 1670, are our most valuable asset. A royalty interest offers the benefit of sharing in production without exposure to the capital or operating costs associated with oil and gas operations. Because we don't incur drilling or reclamation costs on our royalty lands, our sustaining capital expenditure requirements are low. And, because we don't incur operating costs on production from these lands, we achieve high operating netbacks.

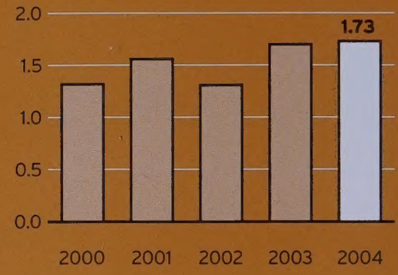
Since 1996, more than 4,200 wells have been drilled on our royalty lands, adding to our reserves and production at no cost to us. This free drilling currently contributes 28% of our royalty production volumes. The continued high level of activity illustrates the ongoing potential of these properties. Whether through infill drilling, targeting new productive zones, or employing new technologies such as horizontal drilling, we expect to benefit from these activities for many years.

Free drilling on our royalty lands offsets our natural production decline rate, thus giving us the freedom to maintain a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders. Without the opportunity to add reserves and production through acquisitions, we will eventually deplete the assets of the Trust.

Transaction prices for oil and gas assets have risen quite substantially over the last two years, reflective of increased competition and a higher commodity price environment. Our acquisition team worked very hard during the year on a number of acquisition opportunities. We completed three acquisitions and, while we were unsuccessful in completing a large acquisition, our bids were competitive and we have confidence in our evaluation process.

**In 2004, we declared record distributions of $1.73 per Trust Unit, representing a payout ratio of 85% of cash flow. Distributions declared since inception total $10.28 per Trust Unit.**

**DISTRIBUTIONS TO UNITHOLDERS ($/unit)**




Our three acquisitions will add approximately 200 boe/d to our 2005 production base, with some upside potential. The production acquired is mainly royalty production and fits well with our strategy of maintaining an asset base of primarily royalty interests. However, two acquisitions occurred in the latter part of the year and had relatively little impact on our 2004 average production. As a result, our production for the year was down 4% from the prior year. Year-over year, net reserves (total proved plus probable) also declined 4%.

We view continuing development on our royalty lands as an essential part of our future success. To date, we have seen no evidence to suggest that this activity is slowing. Although the Western Canadian Sedimentary Basin is maturing, drilling activity continues at a record pace. We expect that drilling on our royalty lands will likewise remain at high levels.

The Canadian Association of Oilwell Drilling Contractors forecasts that the industry will continue to set new records for drilling activity in 2005. There are obviously a number of assumptions around that prediction, including continued strength in commodity prices, availability of skilled labour and political and regulatory stability, particularly as it affects some of the major energy projects in Canada such as oil sands development and the construction of the Mackenzie Valley Pipeline.

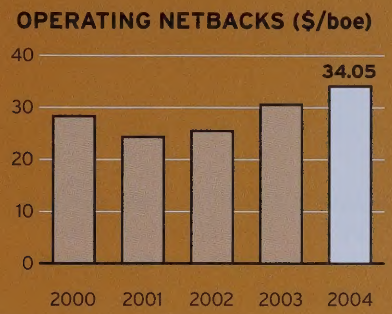
World oil inventories remain low and the timing of new energy supply remains uncertain. Demand remains robust, driven by economic growth in China. Many industry experts believe that we have achieved a new plateau in price expectations. Crude oil prices continue to be high and the outlook for 2005 is positive. However, a global surplus of heavy crude and a lack of upgrading capacity may result in wider differential prices between light and heavy grades of crude. We are particularly vulnerable to swings in the light/heavy oil differential price, as approximately 56% of our oil production (36% of our total production) is heavy oil.

Natural gas, because it is less readily transported, is subject to supply and demand factors within North America. Even with very active drilling levels, supply is unable to keep pace with demand. Additional supplies from proposed northern pipelines or increased liquefied natural gas imports are unlikely to deliver gas into the consuming areas of North America before the end of the decade. Therefore, natural gas prices, which are also influenced by fuel parity with oil prices, are expected to remain firm.

The higher Canadian currency has offset a portion of the economic benefit of higher oil prices because oil is priced in U.S. dollars. Fortunately, with higher commodity prices, the net impact of the strengthening Canadian dollar has not materially damaged our ability to deliver strong financial performance.

For 2005, we currently estimate distributions of $1.55 per Trust Unit. Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices, foreign exchange rates or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators. Our guidance will be updated quarterly throughout the year.

**Our high percentage of royalty income results in superior operating netbacks, which maximizes distributions to Unitholders.**



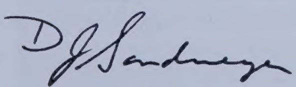

As the rules and guidelines defining disclosure get more complex, we continue to strengthen our governance and administrative processes. In 2004, we began the process of preparing ourselves to meet regulatory requirements relating to certification of internal controls. This requirement will not be mandatory until 2006, but we believe it is important to get an early start. The process involves a significant time commitment on the part of many of our senior technical and financial people to examine, document and adequately test our processes to ensure that they can be relied upon. I would like to thank the individuals involved for their diligent work on this important project.

Our commitment to generate superior returns remains our number one priority, but we are not driven by absolute growth objectives. Our primary goal is to extend cash distributions over the long term by actively managing our assets to sustain reserves and production without diluting our Unitholders. Our strategy to achieve this is to:

- maintain an aggressive audit program to ensure that royalties are correctly calculated and paid when new wells are drilled and that these royalties continue to be paid to us if the properties are transferred to new operators;
- pursue development opportunities to optimize reserves and production on our working interest properties;
- acquire appropriate assets with a bias toward royalty interests. However, subject to threshold requirements in terms of cash flow, return on investment and future development potential, we may also pursue working interest properties and/or corporate acquisitions; and
- maintain a conservative approach to debt management to provide maximum financial flexibility with respect to acquisitions, capital expenditures, or maintaining distributions through a downturn in commodity prices.

In closing, I would like to thank our directors for their ongoing guidance and support and acknowledge the employees of the Manager, Rife Resources Management Ltd. Their continuing efforts and dedication ensure that we are well equipped to take advantage of the opportunities we identify in the coming years. Finally, I want to extend thanks to you, our Unitholders, for your continued confidence in us.

David J. Sandmeyer
President & Chief Executive Officer



March 4, 2005

## INDEPENDENT DIRECTORS

**Five independent directors are elected annually by the Unitholders and two management directors are appointed by the Manager.**

### William W. Siebens

Chairman of the Board, Member, Governance & Nominating Committee

Bill Siebens is President and CEO of Candor Investments Ltd. (Calgary), a private energy and investment corporation. He currently serves as a director of Petro-Canada and the Fraser Institute. He brings special expertise to Freehold with his knowledge of the Trust's royalty lands as a portion of these lands were previously owned by Siebens Oil & Gas Ltd.

### D. Nolan Blades

Chair, Audit Committee, Chair, Reserves Committee, Member, Governance & Nominating Committee

Nolan Blades is President of Sunny Gables Holdings Ltd. (Calgary) and a Professional Engineer with extensive experience in the oil and gas industry. Mr. Blades was President and CEO of Pursuit Resources Corp. from 1993 to 2000, and is currently a director of Real Resources Inc., Gemini Corporation and Canoro Resources Ltd.

### Harry S. Campbell Q.C.

Member, Reserves Committee

Harry Campbell is Managing Partner of the law firm Burnet, Duckworth & Palmer LLP (Calgary). He was admitted to the Alberta Bar in 1974 and has extensive experience with Canadian oil and gas transactions and international petroleum and natural gas matters. Mr. Campbell is currently a director of Delphi Energy Corp. and The Cathay Investment Fund Limited.

### Peter T. Harrison

Member, Audit Committee, Member, Reserves Committee

Peter Harrison is Senior Vice-President of Montrusco Bolton Inc. (Montreal). Mr. Harrison has more than 24 years of investment experience and previously managed Canadian Equities for the CN Investment Division. Mr. Harrison is currently a director of Daylight Energy Trust. He holds a Bachelor of Commerce degree from McGill University, an MBA from the University of Western Ontario and is a Chartered Financial Analyst.

### Dr. P. Michael Maher

Chair, Governance & Nominating Committee, Member, Audit Committee

Michael Maher is a Professor and former Dean of the Haskayne School of Business, University of Calgary. He currently serves as a director of Nicer Technologies and Wellpoint Systems Inc. He has a Bachelor of Science degree in Engineering from the University of Saskatchewan; an MBA from the University of Western Ontario; a PhD from Northwestern University; a Doctor of Commerce (honoris causa) degree from St. Mary's and is a Professional Engineer.

## MANAGEMENT DIRECTORS

### Tullio Cedraschi

Director

Tullio Cedraschi is President and CEO of the CN Investment Division (Montreal). He is currently a director of the Toronto Stock Exchange, Western Oil Sands Inc. and Helix Investments (Canada) Inc. He is a Governor and Past President of the National Theatre School of Canada, and a Governor Emeritus of McGill University, where he received his MBA.

### David J. Sandmeyer

President & CEO
Director

David Sandmeyer is President of Rife Resources Ltd. (Calgary). Prior to joining Rife, he held senior positions with Amoco Canada Petroleum Company Limited for 18 years. He is a former Governor of the Canadian Association of Petroleum Producers. A graduate of the University of Saskatchewan, he holds a Bachelor of Science degree in Mechanical Engineering and is a Professional Engineer.

# GOVERNANCE

**Our governance practices follow the guidelines for effective corporate governance established by the Toronto Stock Exchange.**

The following is a summary of our approach to governance, which is described in more detail in our Information Circular – Management Proxy Statement.

## THE MANAGER

We are managed by Rife Resources Management Ltd., a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for employees of Canadian National Railway Company). The CN Pension Trust Funds own 32% of our Trust Units. The Manager also manages two other entities on behalf of the CN Pension Trust Funds. These are Rife Resources Ltd., a private oil and gas company, and Canpar Holdings Ltd., a private royalty holding company. The assets that were contributed into Freehold Royalty Trust in 1996 were previously owned by Rife and Canpar. The President and all four Vice-Presidents have been actively managing these assets for more than 20 years.

### Conflicts of Interest

Rife and Canpar are managed by the same company that is responsible for our operations. While the mandates of Rife and Canpar are different from ours, the board has addressed potential conflicts of interest of the Manager, which arise primarily out of acquisition activity, through an arrangement that provides for a sharing formula for any acquisitions completed by the Manager on our behalf.

## BOARD INDEPENDENCE

We have a seven-member board, five of whom are independent directors. Unitholders are entitled to elect five directors annually and two directors are appointed by the Manager. The Chairman of the board is an independent director, as are the directors who chair the board's three standing committees.

## BOARD MANDATE

Pursuant to the Management Agreement, the Manager has responsibility for our day-to-day operations, subject to the board's general supervision and direction. In particular, significant operational decisions are made by the board, including:

- issuance of additional Trust Units;
- acquisition and disposition of properties for a purchase price or proceeds in excess of $5 million;
- capital expenditures outside approved budgets;
- establishment of credit facilities; and
- payment of distributions to Unitholders.

The board of directors is responsible in conjunction with the Manager for:

- strategic planning;
- identification of the principal business risks and implementing appropriate systems to manage these risks;
- communication policy; and
- integrity of internal controls and management information systems and monitoring senior management.

The board meets on a quarterly basis (more often, if required) to review operating and financial results.

# BOARD COMMITTEES AND THEIR MANDATES

The primary roles and responsibilities of the three standing committees of the board are summarized below. Each committee has written terms of reference and a mandate approved by the board.

## Audit Committee

**Members: D. Nolan Blades (Chairman), Peter T. Harrison, Dr. P. Michael Maher**, all of whom are unrelated directors.

The Audit Committee mandate includes:

- reviewing and recommending to the board for approval our annual and interim financial statements;
- reviewing and recommending to the board for approval offering documents, the annual information form, annual and interim MD&A, and all public disclosure containing audited or unaudited financial information;
- recommending to the board the appointment of external auditors;
- evaluating and ensuring the independence of our auditors;
- reviewing the Manager's internal control systems; and
- reviewing risk management policies and procedures, including hedging, litigation and insurance.

## Governance & Nominating Committee

**Members: Dr. P. Michael Maher (Chairman), D. Nolan Blades, William W. Siebens**, all of whom are unrelated directors.

The mandate of the Governance and Nominating Committee includes:

- developing governance policies and reviewing and approving annual governance disclosure;
- establishing a long-term plan for composition and size of the board, including a process to identify, recruit and appoint new directors and recommending nominees for election to the board, as well as reviewing the effectiveness of the board, its committees and its individual members;
- reviewing and determining director compensation;
- considering and recommending to the board option grants to outside directors;
- reviewing the general responsibilities and function of the board, its committees and the roles of the Chairman and the Chief Executive Officer;
- assessing the needs of the board in terms of education, frequency, location and conduct of board and committee meetings; and
- considering requests from individual directors or committees to engage outside advisors.

## Reserves Committee

**Members: D. Nolan Blades (Chairman), Harry S. Campbell[1], Peter T. Harrison**, the majority of whom are unrelated directors.

The Reserves Committee mandate includes:

- recommending to the board the appointment of independent reserves evaluators;
- reviewing the Manager's reporting on internal reserves standards and practices;
- reviewing the Manager's procedures for providing information to the Evaluator; and
- reviewing reserves and all public disclosure documents containing reserve information prior to board approval.

1 Mr. Campbell is a related director. He is Managing Partner of Burnet, Duckworth & Palmer LLP which, from time to time, provides legal services to us, to our subsidiary, Freehold Resources Ltd. and to the CN Pension Trust Funds and their affiliates.

# CORPORATE RESPONSIBILITY

**As a subsidiary of the CN Pension Trust Funds, Rife Resources Management Ltd. and its employees have an obligation to maintain the highest standards of business conduct.**

## CODE OF CONDUCT

We have no employees. The people who manage our affairs are employees of our Manager. Rife is a company whose standards of business conduct must be of the highest order. As a subsidiary of the CN Pension Trust Funds, Rife is part of a very large, very visible and very sensitive organization. The employees of Rife, therefore, have an obligation to maintain the highest standards of business conduct. Rife's Code of Business Conduct & Conflict of Interest Policy is distributed to employees of Rife on an annual basis.

## DISCLOSURE AND INSIDER TRADING POLICIES

We have a Disclosure Policy in place to ensure consistent standards and procedures for communication of both material and non-material information. The policy directs the communication of material information to the investing public to ensure information is timely, factual and accurate, and is broadly disseminated in a non-selective manner in accordance with all applicable legal and regulatory guidelines.

We also have an Insider Trading Policy in place to provide our directors and officers and the employees of the Manager with guidelines regarding trading in our securities, including mandatory blackout periods.

Our policies are distributed to employees of the Manager on an annual basis.

## ENVIRONMENT, HEALTH & SAFETY

We do not operate any of our oil and gas assets. The properties in which we own a royalty interest are operated by oil and gas companies that have environmental, health and safety policies in place. A major working interest property located at Hayter, Alberta, is operated by the Manager. The Manager has an Environment, Health and Safety Policy in place to protect the health and safety of its employees, contractors and the public.

### Reclamation Fund

In 1996, we established a reclamation fund to ensure that required funds were available for future reclamation of working interest wells and facilities once they have reached the end of their economic life. We have no reclamation responsibilities on our royalty assets as these are the responsibility of the working interest owners. We contributed $414,000 in cash and interest income to the fund during 2004 and withdrew $57,000, which was spent on reclamation activities. At December 31, 2004, the fund had a balance of $1.6 million.

# OPERATIONS OVERVIEW

**Our properties are geographically widespread throughout western Canada, encompassing more than one million gross acres of land. We have an interest in approximately 15,800 royalty wells and 1,400 working interest wells. This diversity lowers our risk.**

## OUR ASSETS

Our oil and gas assets are diverse and can be described in two main categories: royalty lands and working interest properties. Working interests are participating (lessee) interests in land and are expressed as a fraction or a percentage. Working interest owners pay capital and operating costs and pay royalties to the mineral title owner. We are the recipient of two types of royalty interests: lessor royalties paid to the mineral title owner (lessor) of the mineral rights; and gross overriding royalties, which primarily arise from contractual arrangements between companies. A royalty is a payment made from the gross production at the wellhead. The royalty owner is not responsible for any of the capital or operating costs required to produce the oil or gas. Therefore, a royalty interest is more valuable than a working interest of equal amount.

Acquisitions in 2004 added 39,360 gross acres of undeveloped land to bring our undeveloped land position to 291,729 gross acres at December 31, 2004.

### ACREAGE SUMMARY

| (gross acres)[1] | **2004** | 2003 | 2002 |
|---|---|---|---|
| Alberta | **699,556** | 642,092 | 632,047 |
| Saskatchewan | **339,303** | 340,475 | 341,134 |
| British Columbia | **25,946** | 25,946 | 25,946 |
| Manitoba | **2,224** | 2,224 | 2,224 |
| Total | **1,067,029** | 1,010,737 | 1,001,351 |
| Undeveloped land | **291,729** | 242,205 | 235,061 |

1 Gross acreage represents the total number of acres in which we have an interest.

### DRILLING SUMMARY

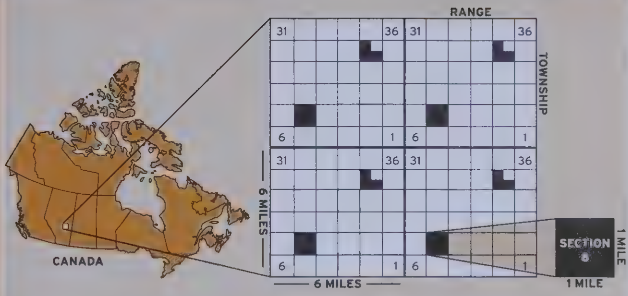
| | **2004** | | 2003 | | 2002 | |
|---|---|---|---|---|---|---|
| | **Gross[1]** | **Net[2]** | Gross[1] | Net[2] | Gross[1] | Net[2] |
| Alberta | **616** | **11.7** | 428 | 10.4 | 491 | 9.6 |
| Saskatchewan | **132** | **5.9** | 199 | 12.5 | 158 | 8.1 |
| British Columbia | **1** | **0.1** | 23 | 0.0 | 14 | 0.0 |
| Manitoba | **12** | **0.0** | 0 | 0.0 | 0 | 0.0 |
| Total | **761** | **17.7** | 650 | 22.9 | 663 | 17.7 |

1 Gross wells means the number of wells in which we have a royalty or working interest.
2 Net wells means the aggregate number of wells obtained by multiplying each gross well by our percentage royalty or working interest therein.

### PRODUCTION SUMMARY

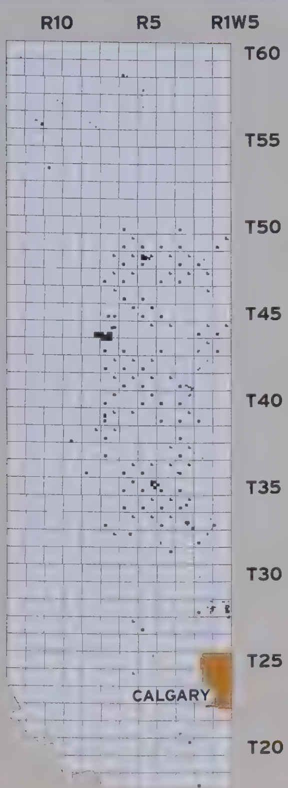
| (boe/d) | **2004** | 2003 | 2002 |
|---|---|---|---|
| Royalty lands | **3,711** | 3,972 | 4,153 |
| Working interest properties | **1,877** | 1,845 | 1,851 |
| Total | **5,588** | 5,817 | 6,004 |
| Potash (tonnes/d) | **7.6** | 7.6 | 7.8 |

**Our royalty lands make a checkerboard pattern across the prairie landscape. These legacy assets, which stem from lands granted by King Charles II to the Hudson's Bay Company in 1670, are our most valuable asset.**




## 2004 HIGHLIGHTS

| Royalty Areas | Wells Drilled (gross) | Wells Drilled (net) | Average Daily Production: Oil and NGL (bbls/d) | Average Daily Production: Natural Gas (Mcf/d) | Average Daily Production: Oil Equivalent (boe/d) | Net Proved Plus Probable Reserves (Mboe) |
|---|---|---|---|---|---|---|
| Western Alberta | 39 | 0.8 | 324 | 2,518 | 743 | 3,823 |
| Saskatchewan Heavy Oil | 14 | 1.1 | 546 | 345 | 604 | 1,895 |
| Northeast Alberta | 55 | 1.7 | 469 | 805 | 603 | 2,529 |
| Southeast Saskatchewan | 51 | 2.1 | 567 | 151 | 593 | 1,650 |
| Southeast Alberta | 406 | 3.5 | 132 | 1,401 | 365 | 1,521 |
| Bashaw/Leduc | 24 | 0.5 | 130 | 1,177 | 326 | 862 |
| Hatton/Gull Lake | 65 | 2.4 | 156 | 672 | 268 | 1,142 |
| Other | 17 | 0.2 | 99 | 657 | 209 | 910 |
| **Total** | **671** | **12.3** | **2,423** | **7,726** | **3,711** | **14,332** |



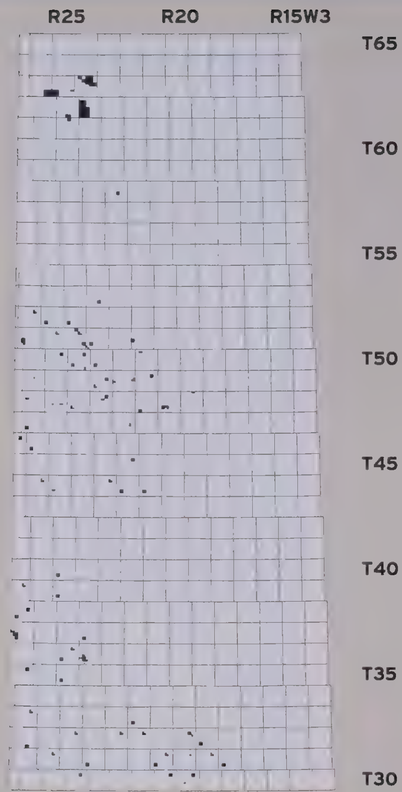

## WESTERN ALBERTA

Extending from the foothills to the northern plains, the Western Alberta royalty area contains a wide distribution of producing fields. Production, which is primarily natural gas and light oil, declined 9% in 2004. The largest property is the Caroline Swan Hills Gas Unit No. 1, with production of 132 boe/d. During 2004, we acquired additional royalty interests at Pembina and Willesden Green, which will contribute approximately 175 boe/d in 2005.

**In 2004, the most active operators were Bonterra Energy Income Trust and ConocoPhillips Canada.**

### 2004 Statistics

Land: 104,608 gross acres
Average royalty interest: 0.6%
Wells: 2,471
Production units: 65
Royalty income: $11.0 million
Production: 743 boe/d



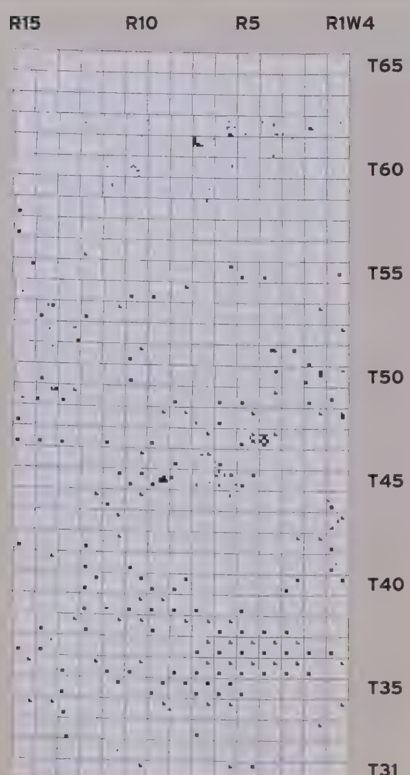

## SASKATCHEWAN HEAVY OIL

The major productive zones in the Saskatchewan Heavy Oil royalty area are the Mississippian Bakken, the Cretaceous Mannville and the Cretaceous Viking formations. Significant revenue properties are the Luseland Bakken pool, the Baldwinton Sparky pool and the Carruthers Cummings pool. Production declined 23% in 2004. This area also experienced a decline in drilling year-over-year.

**In 2004, the most active operators were Baytex Energy Trust and Murphy Oil Company Ltd.**

**2004 Statistics**

Land: 62,398 gross acres
Average royalty interest: 5.3%
Wells: 1,015
Production units: 6
Royalty income: $7.1 million
Production: 604 boe/d

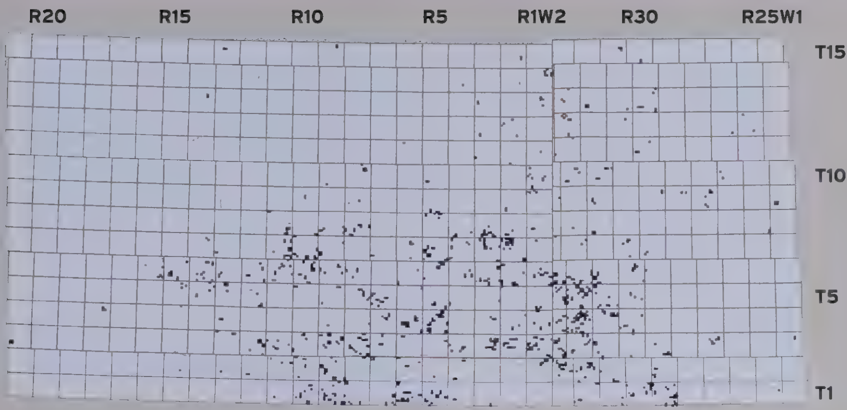

## NORTHEAST ALBERTA

The main producing horizons in the Northeast Alberta royalty area are the Viking and Mannville formations. The northern part of the area is characterized by the production of heavier oil and/or gas from the Mannville sands. Year-over-year, production remained stable. This area contains our second largest royalty property at Hayter, which contributed 150 boe/d during 2004. We also have a 23.52% working interest at Hayter.

**In 2004, the most active operators were Apache Canada Ltd. and Rife Resources Ltd.**

**2004 Statistics**

Land: 123,332 gross acres
Average royalty interest: 1.9%
Wells: 2,018
Production units: 32
Royalty income: $7.6 million
Production: 603 boe/d



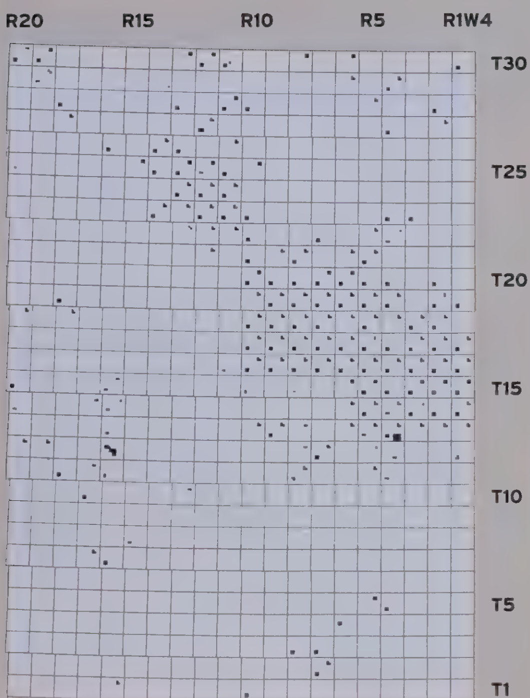

## SOUTHEAST SASKATCHEWAN

The Southeast Saskatchewan royalty area is situated on the northern edge of the Williston Basin. Production, which is primarily light and medium gravity oil, declined 11% in 2004.

**In 2004, the most active operators were Nexen Inc., Crescent Point Energy Trust, Bulldog Energy Inc. and Bison Resources Ltd.**

### 2004 Statistics

Land: 129,287 gross acres
Average royalty interest: 0.6%
Wells: 2,409
Production units: 34
Royalty income: $10.0 million
Production: 593 boe/d

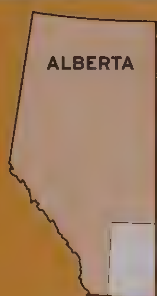

## SOUTHEAST ALBERTA

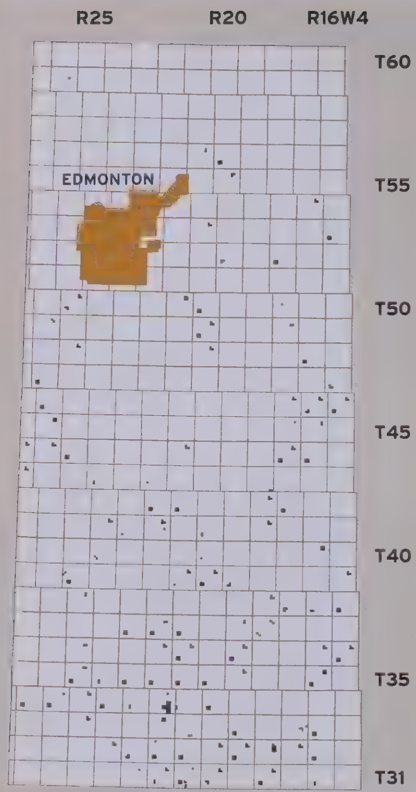
The Southeast Alberta royalty area contains the largest number of gas wells. Although shallow gas is the dominant play, oil production contributes significantly to revenue. Production declined 18% in 2004. This was the most active area for drilling in 2004. However, approximately 50% of the wells drilled in 2004 were not on production at year end.

**In 2004, the most active operators were EnCana Corporation, Enerplus Resources Fund, Advantage Energy Income Fund and ConocoPhillips Canada.**

### 2004 Statistics

Land: 126,918 gross acres
Average royalty interest: 1.0%
Wells: 4,637
Production units: 46
Royalty income: $4.9 million
Production: 365 boe/d





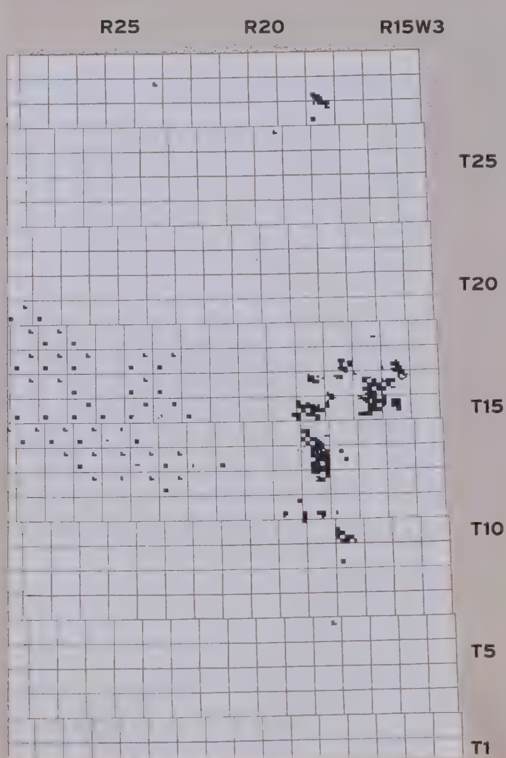

## BASHAW/LEDUC

The Bashaw/Leduc royalty area encompasses a wide diversity of productive zones. Production from this area is primarily natural gas and light oil. The largest properties are the Red Willow Ellerslie gas pool, the Leduc-Woodbend Glauconitic "D" Unit No. 1 and the Halkirk Ellerslie oil pool. Production remained stable in 2004.

**In 2004, the most active operators were Apache Canada Ltd. and 981384 Alberta Ltd.**

### 2004 Statistics

Land: 65,827 gross acres
Average royalty interest: 0.8%
Wells: 1,311
Production units: 38
Royalty income: $4.9 million
Production: 326 boe/d


## HATTON/GULL LAKE

The Hatton/Gull Lake royalty area of southwestern Saskatchewan provides revenue from shallow gas and oil production from interests owned near Swift Current. Production increased 45% in 2004, as a result of successful drilling and a prior period adjustment.

**In 2004, the most active operators were Apache Canada Ltd. and Husky Energy Inc.**

### 2004 Statistics

Land: 124,858 gross acres
Average royalty interest: 0.9%
Wells: 1,379
Production units: 33
Royalty income: $3.3 million
Production: 268 boe/d

# WORKING INTEREST PROPERTIES

**We own various working interests in 90 properties, which represents a more conventional source of oil and gas revenue. In 2004, these assets contributed 14% of distributions to Unitholders. The majority (60%) of our working interest production comes from four properties in Alberta.**


In 2004, we spent $5.8 million and participated in the drilling of 90 (5.4 net) wells. Our 99% success rate reflects the conservative nature of our capital investment program, which excludes participation in high-risk exploratory drilling. Working interest properties accounted for 34% of total production volumes in 2004.

## Hayter

We own a 23.52% working interest and a 6.25% royalty interest in the Hayter property located in east-central Alberta. The Hayter Dina B pool produces 15° API oil from an average net pay interval of approximately 15 metres. Due to the presence of an active bottom water drive, horizontal drilling has been effective in developing the pool. Production increased 10% in 2004 as a result of drilling and the expansion of water injection facilities. Ten (2.4 net) locations are planned in 2005.

## Pembina

We have a 9.97% working interest and a 0.6% royalty interest in the Pembina Cardium Unit No. 9 located 85 miles southwest of Edmonton. Light oil production is from part of the Pembina oilfield, the largest conventional oilfield discovered in Canada. This unit has an extremely long reserve life and has been on an 80-acre, five-spot waterflood pattern for more than 40 years. In 2005, the operator has plans to drill 20 (2.0 net) infill wells, including seven (0.7 net) injection wells.

## Ribstone/Chauvin

Production from Ribstone/Chauvin has grown to 150 boe/d compared with 46 boe/d when we acquired the properties in 1997. Oil and gas produced is primarily from the Mannville sands. Our largest property in this area is a 16.67% interest in the Ribstone Sparky A pool located in Section 34-42-04 W4M, which produced 100 boe/d in 2004.

## Pouce Coupe

We own a 25.56% interest in the Pouce Coupe South Boundary "B" Unit #2 in west-central Alberta. This property is under waterflood and produces light oil from the Boundary Lake formation. Year-over-year, production increased 5%. In 2005, plans include the drilling of two (0.5 net) wells.

### 2004 HIGHLIGHTS

| Working Interest Properties | Working Interest | Wells Drilled | | Average Daily Production: Oil and NGL | Natural Gas | Oil Equivalent | Net Proved Plus Probable Reserves |
|---|---|---|---|---|---|---|---|
| | (%) | (gross) | (net) | (bbls/d) | (Mcf/d) | (boe/d) | (Mboe) |
| Hayter[1] | 23.52 | 11 | 2.6 | 602 | 26 | 606 | 1,944 |
| Pembina[2] | 9.97 | 1 | 0.1 | 205 | 413 | 274 | 2,857 |
| Ribstone/Chauvin | 16.67 | 4 | 0.7 | 100 | 299 | 150 | 152 |
| Pouce Coupe | 25.56 | 0 | 0 | 90 | 88 | 105 | 480 |
| Other (86 properties) | various | 74 | 2.0 | 457 | 1,718 | 742 | 1,398 |
| **Total** | | **90** | **5.4** | **1,454** | **2,544** | **1,877** | **6,831** |

1 Excludes a 6.25% royalty interest (included in the Northeast Alberta royalty area).
2 Includes a 0.6% royalty interest.

# RESERVES

**This annual report contains a summary of the reserves data and other information that has been prepared and filed with securities regulatory authorities in accordance with National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities (NI 51-101).**

The board of directors has, on the recommendation of the Reserves Committee, approved the content and filing of the reserves data. The report has been filed with regulatory authorities and is available on SEDAR at *www.sedar.com.*

## Summary of Reserves

Our oil and gas reserves were independently evaluated by Trimble Engineering Associates Ltd. as at December 31, 2004. Reserves were assigned to 14,637 wells. Net reserves totalled 21.2 million boe, down 4% from year-end 2003. We replaced 65% (2003 – 53%) of annual production through acquisitions and development activities (excluding technical revisions and economic factors). The average cost of net reserve replacement was $12.88 per boe in 2004, compared with $11.35 per boe in 2003. The acquired reserves are mainly royalties which have a greater economic value than working interests and, therefore, command a higher market price. The three-year average cost of reserve replacement is $10.14 per boe. Our three-year average recycle ratio is 2.9.

Based on 2004 net reserves and the evaluator's forecast of 2005 net production, our reserve life index is 10.6 years.

The present value of our future net revenue, discounted at 10%, is $292.2 million, plus $5.1 million for potash, evaluated by the Manager. This represents a 14% increase from 2003, which is primarily related to increased future price expectations and the addition of reserves during 2004. Future net revenue estimates are based on the December 31, 2004 escalated oil and gas price and exchange rate forecasts by an independent qualified reserves evaluator.

**SUMMARY OF NET RESERVES**[1]

| | Proved Developed Producing | Proved Developed Non-Producing | Proved Undeveloped | Total Proved | **Proved Plus Probable** |
|---|---|---|---|---|---|
| Light and medium oil (Mbbls) | 4,587 | 2 | 10 | 4,599 | **6,078** |
| Heavy oil (Mbbls) | 4,544 | — | 267 | 4,811 | **7,483** |
| Natural gas (MMcf) | 24,649 | 591 | 13 | 25,253 | **37,313** |
| NGL (Mbbls) | 1,045 | 16 | (1) | 1,059 | **1,384** |
| **Total** (Mboe) | **14,284** | **116** | **278** | **14,678** | **21,163** |
| Potash[2] (Mtonnes) | 57,553 | — | — | — | **57,553** |

1 Columns may not add due to rounding.
2 Potash reserves, evaluated by Rife Resources Ltd., are not subject to NI 51-101.

**NET PRESENT VALUE**[1]

| | Discounted at | | | |
|---|---|---|---|---|
| ($000s) | 0% | 5% | **10%** | 15% |
| Proved | | | | |
| Developed producing | $ 416,020 | $ 284,842 | **$ 224,751** | $ 189,767 |
| Developed non-producing | 4,037 | 3,405 | **2,943** | 2,594 |
| Undeveloped | 3,657 | 2,987 | **2,487** | 2,108 |
| Total proved | 423,714 | 291,234 | **230,181** | 194,469 |
| Probable | 189,881 | 96,150 | **62,066** | 45,324 |
| **Total proved plus probable** | **$ 613,595** | **$ 387,384** | **$ 292,247** | **$ 239,793** |
| Potash[2] | $ 20,385 | $ 8,719 | **$ 5,137** | $ 3,650 |

1 Forecast prices and costs, before tax, including Alberta Royalty Credit. Based on the December 31, 2004 escalated oil and gas price forecasts by an independent qualified reserves evaluator. Columns may not add due to rounding.
2 Potash price forecast prepared by Rife Resources Ltd.

## NET PRESENT VALUE OF RESERVES BY PRODUCT TYPE[1]

| ($000s) | Total Proved | Net Proved Plus Probable |
|---|---|---|
| Light and medium crude oil | $ 86,297 | **$ 103,025** |
| Heavy oil | 70,198 | **93,502** |
| Natural gas | 73,686 | **95,719** |
| Potash[2] | 5,137 | **5,137** |

1 Forecast prices and costs, before tax, including Alberta Royalty Credit, discounted at 10%. Based on the December 31, 2004 escalated oil and gas price forecasts by an independent qualified reserves evaluator.

2 Potash price forecast prepared by Rife Resources Ltd.

## RECONCILIATION OF NET RESERVES[1]

| | Net Proved (Mboe) | Net Probable (Mboe) | Net Proved Plus Probable (Mboe) | Proved Plus Probable Net Present Value of Future Net Revenue Discounted at 10%, before tax ($000s, forecast prices and costs) |
|---|---|---|---|---|
| December 31, 2003 | 15,437 | 6,615 | **22,052** | **$ 255,791** |
| Extensions and improved recovery | 446 | 347 | **793** | **16,588** |
| Technical revisions | 364 | (579) | **(216)** | **(4,317)** |
| Discoveries | 13 | 11 | **24** | **473** |
| Acquisitions | 321 | 113 | **434** | **12,033** |
| Dispositions | — | — | **—** | **—** |
| Economic factors | (1) | (5) | **(6)** | **57,053** |
| 2004 production | (1,901) | (16) | **(1,917)** | **(45,374)** |
| **December 31, 2004** | 14,678 | 6,485 | **21,163** | **$ 292,247** |
| Change over prior year | (759) | (130) | **(889)** | **36,456** |

1 Forecast prices and costs, before tax, including Alberta Royalty Credit, discounted at 10%. Based on the December 31, 2004 escalated oil and gas price forecasts by an independent qualified reserves evaluator. Columns may not add due to rounding.

## RESERVE LIFE INDEX (RLI)[1]

| | Proved Producing | Total Proved | Proved Plus Probable |
|---|---|---|---|
| Net reserves[2] (Mboe) | 14,284 | 14,678 | **21,163** |
| Net production[2] (Mboe) | 1,809 | 1,851 | **1,991** |
| RLI (years) | 7.9 | 7.9 | **10.6** |

1 Calculated by dividing the evaluator's forecast of 2005 net production into the remaining net reserves (excludes potash reserves).

2 Net reserves and production include the principal products (light and medium crude oil, heavy oil and natural gas) and associated gas and natural gas liquids.

## RESERVE LIFE INDEX (RLI) BY PRINCIPAL PRODUCT[1]

| | Proved Producing | Total Proved | Proved Plus Probable |
|---|---|---|---|
| Light and medium oil | | | |
| Net reserves (Mboe) | 4,552 | 4,562 | **6,027** |
| Net production (Mboe) | 415 | 415 | **441** |
| RLI (years) | 11.0 | 11.0 | **13.7** |
| Heavy oil | | | |
| Net reserves (Mboe) | 4,544 | 4,811 | **7,483** |
| Net production (Mboe) | 748 | 770 | **822** |
| RLI (years) | 6.1 | 6.3 | **9.1** |
| Natural gas | | | |
| Net reserves (Mboe) | 19,450 | 20,041 | **30,540** |
| Net production (Mboe) | 2,711 | 2,814 | **3,126** |
| RLI (years) | 7.2 | 7.1 | **9.8** |

1 Based on principal product type within production group and excludes associated gas and natural gas liquids.

### ANALYSIS OF DEVELOPMENT AND ACQUISITION COSTS

| | Three-year results | 2004[1] | 2003[1] | 2002[2] |
|---|---|---|---|---|
| Development expenditures ($000s) | 14,663 | **5,823** | 5,894 | 2,946 |
| Change in future development capital estimates ($000s) | 2,952 | **(2,593)** | 3,429 | 2,116 |
| Net reserve additions by development (Mboe) | 2,693 | **817** | 911 | 965 |
| Development costs[3] ($/boe) | 6.54 | **3.95** | 10.23 | 5.25 |
| Acquisition expenditures[4] ($000s) | 18,593 | **12,881** | 3,386 | 2,326 |
| Net reserve additions by acquisition (Mboe) | 877 | **434** | 209 | 234 |
| Acquisition costs ($/boe) | 21.20 | **29.68** | 16.20 | 9.94 |
| Total expenditures ($000s) | 33,256 | **18,704** | 9,280 | 5,272 |
| Change in future development capital estimates ($000s) | 2,952 | **(2,593)** | 3,429 | 2,116 |
| Net reserve additions by development and acquisition (Mboe) | 3,570 | **1,251** | 1,120 | 1,199 |
| Development and acquisition costs ($/boe) | 10.14 | **12.88** | 11.35 | 6.16 |

1 2004 and 2003 based on net proved plus probable reserves evaluated under NI 51-101.
2 2002 based on net proved plus half probable reserves evaluated under National Policy 2-B.
3 Development costs equal development expenditures plus change in future capital, divided by reserves added.
4 Includes $785,000 expenditure allocated to undeveloped land in 2004.

### RESERVE REPLACEMENT AND RECYCLE STATISTICS

| ($/boe, except as noted) | Three-year average | 2004 | 2003 | 2002 |
|---|---|---|---|---|
| Operating netback[1] | 29.90 | **34.05** | 30.51 | 25.43 |
| Development and acquisition costs[2] | 10.14 | **12.88** | 11.35 | 6.16 |
| Recycle ratio[3] (times) | 2.9 | **2.6** | 2.7 | 4.1 |

1 Operating netback is calculated as total revenue, less operating costs and royalties, net of Alberta Royalty Credit.
2 Development expenditures, plus change in future capital, plus acquisition costs, divided by net reserves added through development and acquisition activities.
3 The recycle ratio is a key measure of the efficiency in which new reserves are added and is indicative of the value created by investment activities. It is calculated as the operating netback divided by the average cost of acquiring and developing new reserves. The higher the recycle ratio, the better the profitability of our investments.

## NET ASSET VALUE

Net asset value is an estimate of the underlying value of our reserves and undeveloped land, prior to provision for income taxes, interest expense, general and administrative costs and management fees, but taking into consideration estimated royalties, operating costs, other income, capital costs and abandonment costs. Future net revenue estimates are greatly influenced by price forecasts and future reservoir performance.

Using proved plus probable net reserves, our net asset value before tax as of December 31, 2004 (discounted at 10%) was $8.92 per Trust Unit, compared with $8.08 at year-end 2003. Year-over-year, the major variances in the composition of asset value were increases in the value of oil and gas reserves, bank debt and the number of Trust Units outstanding.

### NET ASSET VALUE, AS AT DECEMBER 31, 2004

| | | Discounted at | | |
|---|---|---|---|---|
| ($000s, except unit data) | 0% | 5% | 10% | 15% |
| Present value of net proved plus probable oil and gas reserves[1] | $ 613,595 | $ 387,384 | **$ 292,247** | $ 239,793 |
| Present value of potash reserves[2] | 20,385 | 8,719 | **5,137** | 3,650 |
| Undeveloped land[3] | 5,129 | 5,129 | **5,129** | 5,129 |
| Reclamation fund | 1,646 | 1,646 | **1,646** | 1,646 |
| Working capital | 4,128 | 4,128 | **4,128** | 4,128 |
| Bank debt | (27,000) | (27,000) | **(27,000)** | (27,000) |
| Net asset value | $ 617,883 | $ 380,006 | **$ 281,287** | $ 227,346 |
| Trust Units outstanding | 31,544,236 | 31,544,236 | **31,544,236** | 31,544,236 |
| **Net asset value per Trust Unit** | **$ 19.59** | **$ 12.05** | **$ 8.92** | **$ 7.21** |

1 Evaluated by Trimble Engineering Associates Ltd. and includes Alberta Royalty Credit.
2 Evaluated by Rife Resources Ltd.
3 Evaluated by Seaton-Jordan & Associates Ltd., effective December 31, 2003.

# MANAGEMENT'S DISCUSSION AND ANALYSIS

**The following discussion is management's opinion about our operating and financial results, which include both Freehold Resources Ltd. and Freehold Royalty Trust, for the year ended December 31, 2004 and previous periods, and the outlook for Freehold based on information available as at March 4, 2005.**



The financial information contained herein has been prepared in accordance with Canadian generally accepted accounting principles (GAAP). All comparative percentages are between the years ended December 31, 2004 and 2003 and all dollar amounts are expressed in Canadian currency, unless otherwise noted. This discussion and analysis should be read in conjunction with the audited financial statements and notes contained in this annual report. Additional information about us, including our Annual Information Form, is available on SEDAR at *www.sedar.com.*

## CONVERSION OF NATURAL GAS TO OIL EQUIVALENT

To provide a single unit of production for analytical purposes, natural gas production and reserves volumes are mathematically converted to equivalent barrels of oil (boe). We use the international conversion of six thousand cubic feet of natural gas to one barrel of oil (6 Mcf = 1 bbl). The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

## SUPPLEMENTAL DISCLOSURE

We believe that distributions to Unitholders, cash flow and netback are useful supplemental measures. You are cautioned that distributions to Unitholders should not be construed as an alternate to net income as determined by GAAP. Cash flow, as used in this report, refers to funds generated from operations derived from our Consolidated Statements of Cash Flows. Cash flow represents cash provided by operating activities, before changes in non-cash working capital. We use cash flow to analyze operating performance, leverage and liquidity. Operating netback, which is calculated as average unit sales price less royalties and operating expenses, and investor netback, which deducts administrative and interest expense and income and capital taxes, represent the cash margin for product sold, calculated on a per boe basis. Distributions to Unitholders, cash flow and netback do not have any standardized meanings prescribed by GAAP and, therefore, may not be comparable with the calculations of similar measures for other entities.

## FORWARD-LOOKING STATEMENTS

This MD&A offers our assessment of our future plans and operations as at March 4, 2005, and contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond our control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. You are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Our actual results, performance or achievements could differ materially from those expressed in, or implied by, these forward-looking statements. No assurance can be given that any of the events anticipated will transpire or occur or, if any of them do so, what benefits we will derive from them. We disclaim any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

## ACCOUNTING POLICIES AND CRITICAL ESTIMATES

Our financial statements are prepared within a framework of GAAP selected by management and approved by our board of directors.

The assets, liabilities, revenues and expenses reported in our financial statements depend to varying degrees on estimates made by management. These estimates are based on historical experience and reflect certain assumptions about the future that are believed to be both reasonable and conservative. Management continually evaluates the estimates and assumptions.

An estimate is considered a critical accounting estimate if it requires management to make assumptions about matters that are highly uncertain, and if different estimates that could have been used would have a material impact.

The calculation of depletion is considered a critical accounting estimate. We follow the full cost method of accounting for petroleum and natural gas interests. Oil and gas properties and royalty interests, including the costs of production equipment and future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. An increase in estimated proved oil and gas reserves would result in a corresponding reduction in depletion expense. The current estimates of oil and gas reserves and our future capital expenditures are based on an independent evaluation conducted as of December 31, 2004. Reserve estimates are updated once a year (as at December 31) and when a significant acquisition is completed. The reserve and recovery information provided are only estimates. The actual production and ultimate reserves may be greater than or less than the estimates and the differences may be material.

## RECENT ACCOUNTING AND RELATED PRONOUNCEMENTS

### Asset Retirement Obligations

On January 1, 2004, we adopted the new Canadian accounting standard for asset retirement obligations. We now recognize the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates. This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes. The opening adjustment to 2004 Unitholders' equity was a reduction of $101,000 (2003 – $153,000). This reflects the cumulative impact of accretion and depletion expense, net of the previously recorded cumulative site restoration provision.

We have no asset retirement obligations on our royalty income properties. Our asset retirement obligations arise from our responsibility to abandon and reclaim our net share of all working interest properties. The net present value of our total asset retirement obligation is estimated to be $3.9 million, with the undiscounted value being $9.9 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away. A credit-adjusted risk free rate of 6.25% was used to calculate the present value of the asset retirement obligation.

### Petroleum and Natural Gas Interests

On January 1, 2004, we adopted CICA Accounting Guideline 16, Oil and Gas Accounting – Full Cost. Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties. The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

### Unit Based Compensation

Effective January 1, 2002, the CICA amended Section 3870, Stock Based Compensation and Other Stock Based Payments. The amendment requires that all unit based payments be measured using the fair value method of accounting and recognize the compensation expense on the financial statements. There was no impact on our financial results, since we currently have no options outstanding.

### Internal Controls

On February 4, 2005, Canadian Securities Administrators published for comment proposed Multilateral Instrument 52-111, Reporting on Internal Control over Financial Reporting. Concurrently, revisions were proposed to Multilateral Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings. If adopted, the new rules will conform Canadian financial reporting and certification requirements more closely to those of the U.S. Sarbanes-Oxley Act of 2002. Issuers will be required to establish a suitable control framework, maintain evidence to support management's evaluation and assessment of internal controls, file a management's report on internal controls, and file an auditor's report on internal controls. In addition, the issuer's CEO and CFO would be required to make expanded representations on the establishment, design, effectiveness and weaknesses of internal control over financial reporting, as well as any changes to internal controls. The comment period ends June 6, 2005. While no effective date has been provided, the proposals contemplate that the new rules will apply for financial years ending on or after June 30, 2006.

## VISION, CORE BUSINESS AND STRATEGY

Our vision is to maximize distributions to Unitholders while striving to acquire appropriate assets to provide for long-term growth in value.

Freehold Royalty Trust is structured as a mutual fund trust under the *Income Tax Act* (Canada). This enables us to return the majority of our income to you in a tax-effective manner. We receive revenue from oil and gas properties as reserves are produced, which is paid to Unitholders on a regular basis over the economic life of the properties.

We are one of the largest owners of mineral title lands in western Canada. Our legacy assets stem from lands granted by King Charles II to the Hudson's Bay Company in 1670. Today, most of our land holdings are located south of the North Saskatchewan River, in a checkerboard pattern that extends across the prairie provinces. Our mineral title lands cover about 480,200 acres, our royalty assumption lands cover about 96,400 acres, and we have gross overriding royalty interests in approximately 280,800 acres. In addition, we hold working interests in 199,874 gross (23,324 net) acres.

Royalties offer the benefit of sharing in production, without exposure to the capital costs, operating costs and environmental costs associated with oil and gas production. Our high percentage of royalty income results in superior netbacks, which maximizes distributions to Unitholders.

Our properties are geographically widespread throughout western Canada. We have an interest in approximately 15,800 royalty wells and 1,400 working interest wells and we receive royalty income from approximately 190 industry operators. Royalty rates vary from less than 1% (for some gross overriding royalties) to 20% (for lessor royalties). This diversity lowers our risk.

Our long reserve life, low sustaining capital investment requirements and the fact that so much development occurs on our lands at no cost to us make these assets very well suited to an energy trust.

Our primary goal is to extend cash distributions over the long term by actively managing our assets to sustain reserves and production without diluting our Unitholders. Our strategy to achieve this is to:

- maintain an aggressive audit program;
- pursue development opportunities on our working interest properties;
- acquire appropriate assets with a bias toward royalty interests; and
- maintain a conservative approach to debt management.

## Business Risks and Mitigating Strategies

The operations of an energy trust are subject to virtually the same industry risks and conditions faced by conventional oil and gas companies. The most significant of these include, but are not limited to:

- fluctuations in commodity prices and quality differentials as a result of weather patterns, world and North American market forces or shifts in the balance between supply and demand for crude oil and natural gas;
- variations in currency exchange rates;
- imprecision of reserve estimates and uncertainty of depletion and recoverability of reserves. Our reserves will deplete over time through continued production and we and our lessees may not be able to replace these reserves on an economic basis;
- industry activity levels and intense competition for land, goods and services and qualified personnel;
- stock market volatility and the ability to access sufficient capital from internal and external sources;
- operational or marketing risks resulting in delivery interruptions, delays or unanticipated production declines;
- changes in government regulations and taxation; and
- safety and environmental risks.

As a royalty trust, we are also subject to the following risks:

- as 45 royalty payors account for 90% of our royalty income, changes to their businesses may have a significant effect on our results; and
- higher prime borrowing rates, which may increase interest expense on our debt, and which may make fixed income investments more attractive to investors of Trust Units.

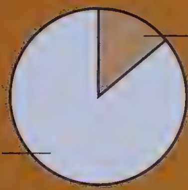
The issue of personal liability was resolved through provincial legislation in both Alberta and Ontario. In Alberta, the *Income Trusts Liability Act* came into force on July 1, 2004 and, in Ontario, legislation was enacted through the *Trust Beneficiaries Liability Act 2004*, which came into force as of December 16, 2004.

We employ the following strategies to mitigate these risks:

- we have an interest in more than 17,000 oil and gas wells across western Canada. This diversified revenue stream limits the size of any one property with respect to our total assets;
- we are not liable for abandonment and reclamation costs on our royalty lands;
- due to our high percentage of royalty lands, we have one of the lowest all-in cost structures of our peer group. In addition, we maintain focus on controlling direct costs to maximize profitability;
- we maintain an aggressive auditing program to ensure that royalties are paid on our production from our lands, that our royalties paid are in accordance with the prices obtained by the royalty payor and that unwarranted or excessive deductions are not being taken. During 2004, our audit staff issued audit exception queries amounting to $1.7 million, bringing the total amount of audit exception queries since 1997 to $13.2 million, $11.9 million of which has been recovered.
- we adhere to strict investment criteria for acquisitions, seeking royalty and working interest properties that have high netbacks, long reserve life, low risk development potential and product diversification;
- we market our products to a diverse range of buyers. Currently, we do not have any commodity price, exchange rate or interest rate hedging programs in place. This policy is subject to regular review;
- we employ a qualified team of oil and gas professionals with many years of experience and knowledge in managing our assets;
- we maintain levels of liability insurance that meet or exceed industry standards; and
- we employ a conservative approach to debt management. As circumstances warrant, we allocate a portion of cash flow to debt repayment.

**Our royalty lands continue to be a distinguishing feature. In 2004, 86% of distributions to Unitholders came from royalty production.**

**2004 DISTRIBUTIONS BY SOURCE**




# RESULTS OF OPERATIONS

Our results are largely influenced by the price we receive for our oil and gas production. Commodity prices have demonstrated considerable strength in the last three years, resulting in increasing cash flow and distributions to Unitholders, despite modestly declining production volumes.

## Selected Annual Data

| ($000s, except per unit data) | **2004** | 2003 | 2002 |
|---|---|---|---|
| Revenue, net of royalties | **75,514** | 69,969 | 60,434 |
| Net income[1] | **36,892** | 37,078 | 27,531 |
| Per Trust Unit, basic and diluted ($) | **1.17** | 1.19 | 0.91 |
| Total assets | **208,001** | 211,872 | 226,104 |
| Long-term debt | **27,000** | 18,000 | 30,000 |
| Distributions to Unitholders | **54,490** | 53,149 | 39,530 |
| Per Trust Unit[2] ($) | **1.73** | 1.70 | 1.31 |

1 2003 and 2002 restated.
2 Based on the number of Trust Units issued and outstanding at each record date.

## Distributions to Unitholders

As of December 31, 2004, we have declared a total of $10.28 per Trust Unit in distributions since inception, returning more than the $10 original investment to investors who participated in the initial public offering in November 1996. The following analysis illustrates the advantage of our royalty lands. Mineral title and gross overriding royalty lands accounted for 67% of gross revenue and 86% of our distributions in 2004.

**COMPONENTS OF 2004 DISTRIBUTIONS**

| ($000s, except as noted) | Royalty Lands | Working Interest Properties | **Total Trust** |
|---|---|---|---|
| Gross revenue | $ 52,677 | $ 25,814 | **$ 78,491** |
| Royalty expense[1] | — | (2,977) | **(2,977)** |
| Net revenue | 52,677 | 22,837 | **75,514** |
| Operating expense | — | (5,860) | **(5,860)** |
| Net operating income | 52,677 | 16,977 | **69,654** |
| General and administrative expense | (2,326) | (1,176) | **(3,502)** |
| Interest expense | (448) | (187) | **(635)** |
| Income and capital taxes | — | (1,147) | **(1,147)** |
| Funds generated from operations (cash flow) | 49,903 | 14,467 | **64,370** |
| Reclamation fund contributions | — | (414) | **(414)** |
| Capital expenditures | — | (5,823) | **(5,823)** |
| Changes in debt | 9,000 | — | **9,000** |
| Net acquisition costs | (12,547) | (514) | **(13,061)** |
| Changes in working capital | 278 | 140 | **418** |
| **Distributions to Unitholders** | $ 46,634 | $ 7,856 | **$ 54,490** |
| Percentage contribution | 86% | 14% | **100%** |

1 Net of Alberta Royalty Credit.

The following reconciliation shows the deductions from cash flow to arrive at distributions to Unitholders. In 2004, we distributed 85% of cash flow. Since inception in late 1996, we have paid out 84% of our total cash flow.

**PAYOUT RATIO[1]**

| ($000s, except as noted) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Funds generated from operations (cash flow) | **$ 64,370** | $ 60,692 | $ 51,607 |
| Reclamation fund contributions | **(414)** | (317) | (240) |
| Development expenditures | **(5,823)** | (5,894) | (2,946) |
| Changes in debt | **9,000** | (1,499) | (3,000) |
| Net acquisition costs | **(13,061)** | (3,386) | (2,326) |
| Changes in working capital | **418** | 3,553 | (3,565) |
| Distributions to Unitholders | **$ 54,490** | $ 53,149 | $ 39,530 |
| Payout ratio[1] | **85%** | 88% | 77% |

1 Distributions to Unitholders as a percentage of cash flow.

## Netback

Netback, calculated on a boe basis, represents the cash margin on the sale of oil and gas. Operating netback is calculated by subtracting royalty expenses and operating costs from revenues. On the majority of our production, we receive royalty income from gross production revenue – before deduction of third-party royalty expenses and operating costs. We do not incur capital expenditures, operating expenses, abandonment or site restoration expenses on our royalty production. The following netback analysis demonstrates the positive effect of this royalty advantage.

**2004 NETBACK ANALYSIS**

| ($ per boe) | Royalty Lands | Working Interest Properties | Total Trust |
|---|---|---|---|
| Gross revenue[1] | $ 38.78 | $ 37.57 | **$ 38.38** |
| Royalty expense (net of ARC) | — | (4.33) | **(1.46)** |
| Net revenue | 38.78 | 33.24 | **36.92** |
| Operating expense | — | (8.53) | **(2.87)** |
| **Operating netback** | 38.78 | 24.71 | **34.05** |
| General and administrative expense | (1.71) | (1.71) | **(1.71)** |
| Interest expense | (0.33) | (0.27) | **(0.31)** |
| Income and capital taxes | — | (1.67) | **(0.56)** |
| Funds generated from operations (cash flow) | 36.74 | 21.06 | **31.47** |
| Reclamation fund contributions | — | (0.60) | **(0.20)** |
| Capital expenditures | — | (8.48) | **(2.85)** |
| Changes in debt | 6.63 | — | **4.40** |
| Net acquisition costs | (9.24) | (0.75) | **(6.38)** |
| Changes in working capital | 0.20 | 0.20 | **0.20** |
| **Investor netback[2]** | $ 34.33 | $ 11.43 | **$ 26.64** |

1 Includes potash revenue, sulphur revenue and other.
2 Excludes management fee paid in Trust Units.

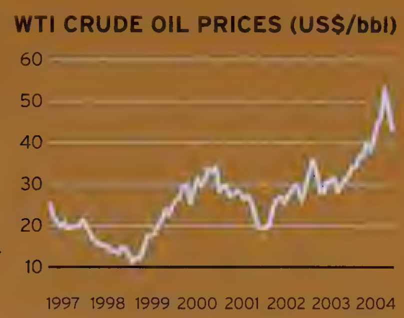
**OPERATING NETBACK**

| ($ per boe) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Royalty lands | **$ 38.78** | $ 34.42 | $ 28.52 |
| Working interest properties | **24.71** | 22.08 | 18.53 |
| Total Trust | **34.05** | 30.51 | 25.43 |

**OPERATING NETBACK BY PRODUCT TYPE**

| | 2004 | 2003 | 2002 |
|---|---|---|---|
| Light and medium oil ($/bbl) | **$ 41.17** | $ 34.87 | $ 31.46 |
| Heavy oil ($/bbl) | **26.87** | 23.51 | 24.32 |
| Natural gas ($/Mcf) | **5.75** | 5.62 | 3.39 |
| NGL ($/bbl) | **33.55** | 27.66 | 22.65 |
| Combined ($/boe) | **34.05** | 30.51 | 25.43 |

**Our results are largely influenced by the prices we receive for our production. In 2004, average WTI crude oil prices were 33% higher than in 2003 and 59% higher than in 2002.**




## Quarterly Review

The table below is a summary of our performance for the past eight quarters. This presentation illustrates the fluctuations in pricing experienced since the beginning of 2003, and the resultant effect on our quarterly financial results. As oil and gas prices are denominated in U.S. dollars, realized selling prices in Canadian dollars are influenced by currency exchange rates. The Canadian dollar began to strengthen in the second quarter of 2003, reducing Canadian dollar price realizations. The Canadian dollar is expected to remain strong in 2005. Natural gas prices, which were exceptionally high in the first quarter of 2003, moderated somewhat in subsequent quarters before rising to average above $7 per Mcf again in the fourth quarter of 2004. Heavy grades of crude oil sell at a discount to light oil. The light/heavy differential price began to widen toward the end of the third quarter of 2004, reaching unprecedented levels in the fourth quarter that have persisted into 2005.

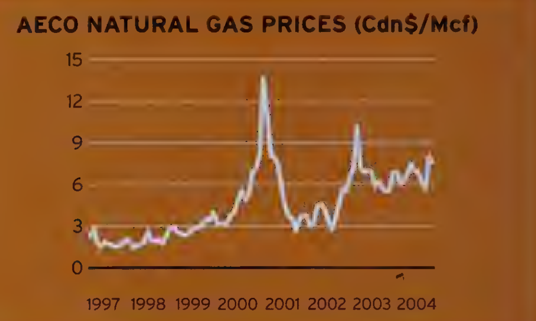
On December 16, 2004, we acquired certain royalty interests in 10,880 acres of land in the Willesden Green area of Alberta for $10 million (prior to adjustments). The acquisition was effective October 1, 2004 and was funded through our existing bank facilities. In 2005, these properties will add approximately 175 boe/d of royalty production, primarily natural gas.

**QUARTERLY RESULTS**

| | 2004 | | | | 2003 | | | |
|---|---|---|---|---|---|---|---|---|
| ($000s, except as noted) | **Q4** | **Q3** | **Q2** | **Q1** | Q4 | Q3 | Q2 | Q1 |
| Revenue, net of royalty expense | **19,204** | **19,994** | **19,066** | **17,250** | 15,230 | 16,865 | 17,070 | 20,804 |
| Funds generated from operations | **16,153** | **17,409** | **16,428** | **14,380** | 12,691 | 14,714 | 14,922 | 18,365 |
| Per Trust Unit ($) | **0.51** | **0.55** | **0.52** | **0.46** | 0.40 | 0.47 | 0.48 | 0.60 |
| Distributions to Unitholders | **15,449** | **14,808** | **12,593** | **11,640** | 12,575 | 12,545 | 15,631 | 12,398 |
| Per Trust Unit ($) | **0.49** | **0.47** | **0.40** | **0.37** | 0.40 | 0.40 | 0.50 | 0.40 |
| Payout ratio (%) | **96%** | **85%** | **77%** | **81%** | 99% | 85% | 105% | 68% |
| Net income[1] | **9,397** | **10,306** | **9,515** | **7,674** | 5,947 | 8,868 | 9,334 | 12,929 |
| Per Trust Unit, diluted ($) | **0.30** | **0.33** | **0.30** | **0.24** | 0.19 | 0.28 | 0.30 | 0.42 |
| Long-term debt | **27,000** | **17,000** | **17,000** | **18,000** | 18,000 | 17,500 | 18,500 | 17,500 |
| Daily production (boe/d) | **5,575** | **5,447** | **5,757** | **5,577** | 5,768 | 5,909 | 5,746 | 5,847 |
| Average selling price ($/boe) | **38.37** | **40.96** | **37.37** | **35.00** | 29.51 | 32.15 | 33.49 | 40.97 |
| Operating netback ($/boe) | **34.67** | **36.85** | **33.57** | **31.18** | 25.88 | 28.61 | 30.47 | 37.18 |
| Exchange rate (US$/Cdn$) | **0.8195** | **0.7651** | **0.7357** | **0.7590** | 0.7600 | 0.7247 | 0.7158 | 0.6626 |
| WTI crude oil (US$/bbl) | **48.28** | **43.88** | **38.31** | **35.14** | 31.18 | 30.20 | 28.91 | 33.86 |
| Bow River heavy oil ($/bbl) | **36.10** | **41.96** | **37.31** | **34.93** | 28.53 | 30.79 | 31.61 | 39.79 |
| Light/heavy oil differential ($/bbl) | **21.60** | **14.29** | **13.29** | **10.67** | 11.02 | 10.13 | 9.51 | 11.16 |
| AECO natural gas ($/Mcf) | **7.08** | **6.66** | **6.80** | **6.61** | 5.59 | 6.29 | 6.99 | 7.92 |

1 2003 restated.

**In 2004, average AECO natural gas prices were 1% higher than in 2003 and 67% higher than in 2002.**




## REVENUE

We receive revenue from approximately 190 industry operators. During 2004, our top 15 royalty payors accounted for approximately 65% of our royalty income. These companies were (listed alphabetically): Apache Canada Ltd., Bison Resources Ltd., BP Canada Energy Company, Canadian Natural Resources Limited, ConocoPhillips Canada Energy Partnership, Devon Canada, EnCana Corporation, Enerplus Resources Corporation, Husky Oil Operations Limited, NAL Resources Limited, Nexen Petroleum Canada, Northrock Resources Ltd., Shell Canada Limited, Talisman Energy Canada and Upton Resources Inc.

The accompanying table demonstrates the net effect of price and volume variances on gross revenue. Gross revenue increased 7% to $78.5 million in 2004, despite lower production volumes. Higher oil prices contributed the majority of the revenue increase in 2004.

**GROSS REVENUE VARIANCES**

| ($000s) | **2004 vs. 2003** | 2003 vs. 2002 |
|---|---|---|
| Oil and NGL | | |
| Production increase (decrease) | **$ (1,637)** | $ (2,471) |
| Price increase | **7,896** | 2,765 |
| Net increase | **6,259** | 294 |
| Natural gas | | |
| Production increase (decrease) | **(1,314)** | 285 |
| Price increase | **400** | 9,295 |
| Net increase (decrease) | **(914)** | 9,580 |
| Other revenue increase (decrease) | **(20)** | 149 |
| Gross revenue increase | **$ 5,325** | $ 10,023 |

### Production

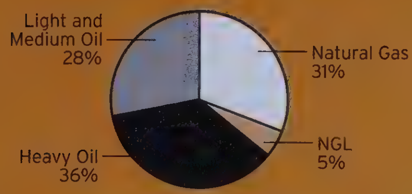
Our production base is geographically widespread throughout western Canada, with the majority of properties located in Alberta. On a boe basis, 69% of our production is derived from oil and natural gas liquids, and 52% of this liquids production (36% of total boe production) is heavy oil. In 2004, production from working interest wells increased 2%, mainly due to the successful drilling program at Hayter and a prior period accounting adjustment, while royalty production declined 7%.

**AVERAGE DAILY PRODUCTION BY PRODUCT TYPE**

| | **2004** | 2003 | 2002 |
|---|---|---|---|
| Light and medium oil (bbls/d) | **1,580** | 1,586 | 2,221 |
| Heavy oil (bbls/d) | **2,014** | 2,102 | 1,705 |
| NGL (bbls/d) | **283** | 317 | 288 |
| Total oil and NGL (bbls/d) | **3,877** | 4,005 | 4,214 |
| Natural gas (Mcf/d) | **10,270** | 10,872 | 10,746 |
| Oil equivalent (boe/d) | **5,588** | 5,817 | 6,004 |
| Total annual production (Mboe) | **2,045,345** | 2,123,293 | 2,191,333 |
| Potash (tonnes/d) | **7.6** | 7.6 | 7.8 |

**On a boe basis, 69% of our production is derived from oil and natural gas liquids, and 52% of this liquids production (36% of total production) is heavy oil.**

**2004 PRODUCTION PROFILE**




**PRODUCTION RECONCILIATION**

| (boe/d) | Royalty Lands | Working Interest Properties | **Total Trust** |
|---|---|---|---|
| 2003 average daily production rate | 3,972 | 1,845 | **5,817** |
| 2003 development | 358 | 185 | **543** |
| 2004 development | 78 | 139 | **217** |
| 2004 acquisitions | 25 | — | **25** |
| Natural decline | (722) | (292) | **(1,014)** |
| **2004 average daily production rate** | 3,711 | 1,877 | **5,588** |

## Product Prices

Commodity prices continued to demonstrate strength in 2004. WTI crude oil rose 33%. However, Bow River heavy oil increased only 15%, reflecting wider price differentials for heavy oil. In 2004, we started to see a growing price differential, due to a surplus of heavy crude and a lack of upgrading capacity. In the fourth quarter of 2004, the average differential climbed above $20 per barrel and, to date in 2005, we have experienced price differentials as high as $25 per barrel. Year-over-year, the Canadian dollar rose 8% against the U.S. dollar, an important factor since oil is priced in U.S. dollars. The average AECO natural gas price was 1% higher in 2004.

**AVERAGE BENCHMARK PRICES**

| | **2004** | 2003 | 2002 |
|---|---|---|---|
| WTI crude oil (US$/bbl) | **41.40** | 31.04 | 26.08 |
| Bow River heavy oil (Cdn$/bbl) | **37.60** | 32.68 | 31.67 |
| Light/heavy oil differential (Cdn$/bbl) | **14.94** | 10.46 | 8.27 |
| AECO natural gas (Cdn$/Mcf) | **6.79** | 6.70 | 4.07 |
| Exchange rate (US$/Cdn$) | **0.7698** | 0.7158 | 0.6369 |

In 2004, our average selling price reached a record $37.91 per boe, up 11% from 2003. However, an 8% increase in the value of the Canadian dollar and an increase in light/heavy oil differential prices resulted in a lower realized price for our oil production relative to the benchmark WTI price. The differential has a significant impact on our realizations, as more than half of our oil production is heavy. The cost of purchased condensate, used as a diluent and blending agent for transport of heavy oil, has also risen dramatically in recent months.

**AVERAGE SELLING PRICES**

| | **2004** | 2003 | 2002 |
|---|---|---|---|
| Oil ($/bbl) | **$ 38.08** | $ 32.77 | $ 31.25 |
| NGL ($/bbl) | **37.29** | 30.95 | 25.09 |
| Oil and NGL ($/bbl) | **38.03** | 32.63 | 30.83 |
| Natural gas ($/Mcf) | **6.28** | 6.18 | 3.81 |
| Oil equivalent ($/boe) | **37.91** | 34.01 | 28.44 |
| Potash ($/tonne) | **167.37** | 133.36 | 143.33 |

### Marketing and Hedging

Our royalty lands consist of a large number of royalty properties and generally small volumes per property. A provision of the leases calls for our natural gas to be marketed with the lessees' production. We have chosen to market our oil production in the same manner.

We market most of our working interest oil production using 30-day contracts to ensure the highest competitive pricing. We have elected to market the majority of our natural gas production with the operators' gas.

It has been our position to accept prices in the market and our production remains unhedged. This policy is subject to regular review by our board of directors.

## EXPENSES

### Royalties Paid

Oil and gas producers pay royalties to the owners of mineral rights from whom they hold leases. These are paid to the Crown (provincial and federal government) and freehold mineral title owners. Royalties are directly related to prices and the volume of oil and gas sales. In 2004, royalties paid on production relating to ownership in working interest properties totalled $3 million, or 4% of gross revenue.

**ROYALTY EXPENSES**

| ($000s, except as noted) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Working interest properties | **2,977** | 3,197 | 2,709 |
| Per boe ($) | **4.33** | 4.75 | 4.01 |
| Total royalty expenses[1] | **2,977** | 3,197 | 2,709 |
| Total Trust[2] ($/boe) | **1.46** | 1.51 | 1.24 |
| As a percentage of gross revenue | **4%** | 4% | 4% |

1 Net of Alberta Royalty Credit.

2 We do not incur royalty expenses on production from our royalty lands. As the royalty owner, we receive the royalty as income from other companies.

### Operating Expenses

Operating expenses are comprised of direct costs incurred and costs allocated among oil, natural gas and natural gas liquids production. Operating expenses for working interest properties rose 13% (11% per boe) in 2004. The increase stems largely from higher electricity and fuel costs in 2004 and prior period adjustments. In addition, with industry activity at record levels, the demand for oilfield goods and services is intense and the energy sector has been experiencing cost inflation. We are somewhat sheltered from the effects of increased costs as the majority of our production comes from our royalty lands, which are not subject to these expenses. On a boe basis, operating costs of our total operations (including the royalty lands) rose 18% year over year, largely due to lower royalty production volumes in 2004.

**OPERATING EXPENSES**

| ($000s, except as noted) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Working interest properties | **5,860** | 5,190 | 4,679 |
| Per boe ($) | **8.53** | 7.71 | 6.93 |
| Total operating expenses | **5,860** | 5,190 | 4,679 |
| Total Trust[1] ($/boe) | **2.87** | 2.44 | 2.14 |
| As a percentage of gross revenue | **7%** | 7% | 7% |

1 We do not incur operating costs on our royalty lands.

## General and Administrative Expenses

Our Manager is a wholly owned subsidiary of Rife Resources Ltd., which is 100% owned by the CN Pension Trust Funds (the pension funds for the employees of Canadian National Railway Company). We reimburse the Manager for overhead expenses incurred on our behalf. During the year, the Manager charged us $2.6 million (2003 – $2.3 million) in general and administrative costs. At December 31, 2004, there was $393,000 (2003 – $343,000) included in accounts payable relating to these costs.

We have significant land administration, accounting and auditing requirements to administer and collect royalty payments relating to approximately 15,800 oil and gas wells. This includes systems to track lessee activity on the royalty lands. General and administrative expenses as a percentage of gross revenue have remained constant at 4% for the past three years.

We experienced higher costs in 2004 as a result of increased staff levels and higher costs associated with regulatory compliance and financial reporting obligations. We also began the work of evaluating internal controls in 2004. The anticipated cost of the project is expected to reach $500,000, of which $29,019 has been incurred to date.

**GENERAL AND ADMINISTRATIVE EXPENSES**

| ($000s, except as noted) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Gross general and administrative expenses | **3,610** | 2,987 | 2,967 |
| Less overhead recoveries | **(108)** | (121) | (144) |
| Net general and administrative expenses | **3,502** | 2,866 | 2,823 |
| Per boe ($) | **1.71** | 1.35 | 1.29 |
| As a percentage of gross revenue | **4%** | 4% | 4% |

## Management Fees

As part of the Management Agreement, the Manager receives a quarterly management fee paid in Trust Units. The Manager also earns an acquisition fee of 1.5% of the purchase price of oil and gas properties which we acquire. This fee is charged to capital assets as part of the properties acquired.

During 2004, the Manager received 90,000 Trust Units as the management fee, unchanged from 2003. The change in the ascribed value of management fees reflects the higher market price of our Trust Units during 2004. The Manager also received a fee of $197,000 relating to acquisitions completed during 2004. Since inception in late 1996, the Manager has received total fees of $8.2 million, representing 2.8% of distributions for the period.

The Management Agreement has a term of three years and will be automatically renewed on November 26, 2007, unless terminated.

**MANAGEMENT FEES**

| ($000s, except as noted) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Management fees (paid in Trust Units)[1] | **1,428** | 1,235 | 971 |
| Acquisition fees (1.5%) | **197** | 52 | 38 |
| Total fees | **1,625** | 1,287 | 1,009 |
| Per boe ($) | **0.79** | 0.61 | 0.46 |
| As a percentage of gross revenue | **2%** | 2% | 2% |
| As a percentage of distributions | **3%** | 2% | 3% |

1 The ascribed value of the management fees is based on the closing Trust Unit price at the end of each quarter.

## Interest Expense

Total interest expense declined 18% to $0.6 million during 2004, primarily due to lower average debt levels and lower prime borrowing rates.

**INTEREST EXPENSE**

| ($000s, except per boe) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Interest on operating line | **7** | 2 | 16 |
| Interest on long-term debt | **628** | 776 | 1,044 |
| Net interest expense | **635** | 778 | 1,060 |
| Per boe ($) | **0.31** | 0.37 | 0.48 |
| As a percentage of gross revenue | **1%** | 1% | 2% |

## Depletion and Ceiling Test

Oil and gas properties and royalty interests, including the cost of production equipment and future capital costs associated with proven reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties payable (see Accounting Policies and Critical Estimates).

During 2004, the provision for depletion and depreciation was $25.7 million ($12.55 per boe), compared with $21.9 million ($10.21 per boe) in 2003. Reserves are independently evaluated on an annual basis. For the first three quarters of 2004, the estimate of proved reserves was based on the independent evaluation dated December 31, 2003, adjusted for acquisitions and production. The fourth quarter results were adjusted to reflect the annual reserve evaluation as at December 31, 2004.

Our ceiling test calculation, performed at December 31, 2004, resulted in no impairment loss. The future prices used in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for our quality, transportation, and contract differences.

## Reclamation Fund

We are liable for ongoing environmental obligations and for the ultimate reclamation of the working interest properties upon abandonment. No similar responsibilities arise from the royalty lands. Ongoing environmental obligations are funded from cash flow. At December 31, 2004, our estimated share of future environmental and reclamation obligations for the working interest properties is approximately $9.9 million.

A reclamation fund was established when the Trust was formed. The fund consists of cash invested in an interest-bearing account and is funded by quarterly cash payments. In 2004, contributions to the reclamation fund totalled $414,000, including interest. For 2005, quarterly contributions will remain at $100,000, plus interest, to ensure that future obligations can be met.

**RECLAMATION FUND SUMMARY**

| ($000s) | Cumulative Since Inception | **2004** | 2003 | 2002 |
|---|---|---|---|---|
| Reclamation fund, beginning balance | $ nil | **$ 1,289** | $ 1,006 | $ 884 |
| Reclamation fund contributions | 2,105 | **414** | 317 | 240 |
| Expenditures on reclamation | (459) | **(57)** | (34) | (118) |
| Reclamation fund, ending balance | 1,646 | **1,646** | 1,289 | 1,006 |

## Taxes

Freehold Royalty Trust is a taxable trust under the *Income Tax Act* (Canada). We distribute substantially all of our taxable income to you as a Unitholder. By doing so, exposure to current tax at the trust level is eliminated. In addition, we are exempt from future income taxes because we are contractually committed to distribute all of our income to Unitholders.

Capital taxes consist primarily of the Saskatchewan Capital Tax applied to both taxable capital and gross revenues in that province. Our subsidiary, Freehold Resources Ltd., is a Canadian corporation subject to tax in various jurisdictions. Freehold Resources Ltd. can deduct royalty payments to us in determining its taxable income, and is generally liable for income taxes on its 1% residual interest. Freehold Resources Ltd. is subject to federal and capital tax in any jurisdiction (federal and provincial) in which it has a permanent establishment. In 2004, Freehold Resources Ltd. had taxable income that gave rise to current income taxes of $1,031,000 (2003 – $340,000).

In the fourth quarter of 2004, we recorded a future income tax recovery of $219,000 related to the operations of Freehold Resources Ltd. due to enacted legislation that lowers corporate tax rates over the next five years. This resulted in a future income tax provision of $157,000 for the year ended December 31, 2004. The future income tax provision does not impact our current distributions as it is a non-cash charge.

**TAXES**

| ($000s) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Large Corporations Tax | $ — | $ 23 | $ 48 |
| Provincial Capital Tax | 116 | 80 | 95 |
| Current income tax | 1,031 | 340 | 122 |
| Total | $ 1,147 | $ 443 | $ 265 |

**TAX POOLS**

| ($000s) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Canadian oil and gas property expense | $ 160,338 | $ 166,767 | 171,205 |
| Canadian development expense | 5,971 | 6,710 | 4,913 |
| Canadian exploration expense | — | — | — |
| Capital cost allowance | 6,571 | 5,763 | 6,168 |
| Unit issue expenses | 269 | 537 | 806 |
| Total[1] | $ 173,149 | $ 179,777 | $ 183,092 |

1 These amounts represent our direct tax pools as well as the tax pools of our subsidiary, Freehold Resources Ltd.

## Unitholder Taxation

We are entitled to claim certain tax deductions available to all owners of oil and gas properties. By using two principal deductions – the Canadian Oil and Gas Property Expense and the Resource Allowance – cash distributions in the Trust's initial years were sheltered from income tax. Generally over time, an increasing percentage of the annual distributions will become taxable. The increase in the taxable portion is a result of a general reduction in tax pools available for future claims.

For income tax purposes, only cash payments received in each calendar year are subject to Canadian income tax. We paid $1.71 per Trust Unit as cash distributions during the 2004 taxation year.

For Canadian tax purposes, 68% of these distributions ($1.1628 per Trust Unit) were taxable to you as a Unitholder as other income and 32% ($0.5472 per Trust Unit) was a tax deferred return of capital. The tax deferred return of capital will reduce your adjusted cost base for purposes of determining a capital gain or loss upon disposition of the Trust Units.

In 2005, due to continued high commodity prices, we currently estimate that, for residents of Canada, approximately 75% of distributions to Unitholders will be taxable as other income and 25% will be a tax-deferred return of capital.

## LIQUIDITY AND CAPITAL RESOURCES

We have a $50 million committed production facility on which $27 million was drawn at December 31, 2004. This facility is structured as a one-year committed revolving credit facility, extendable annually. In the event that the lender does not consent to an extension, the revolving credit facility will revert to a three-year, non-revolving amortizing term loan with equal quarterly principal repayments. In addition, we have available a $15 million demand operating facility and a US$10 million swap facility which was unused at year end.

In December 2004, long-term debt increased by $9 million. At December 31, 2004, we had no short-term debt outstanding and long-term debt was $27 million. We have approximately $38 million of available capacity under our credit facilities, which is an important part of our acquisition strategy. A strong balance sheet enables us to actively seek opportunities to further augment production and reserves through the purchase of producing properties, in particular, royalty assets.

Our ratio of net debt (long-term debt less positive working capital) to trailing cash flow remains among the lowest in the energy trust sector, at 0.4:1.

**DEBT ANALYSIS**

| ($000s) | **2004** | 2003 | 2002 |
|---|---|---|---|
| Long-term debt | **$ 27,000** | $ 18,000 | $ 30,000 |
| Short-term debt (operating line) | **—** | — | — |
| Less working capital | **4,128** | 4,367 | 7,920 |
| Net debt obligations | **$ 22,872** | $ 13,633 | $ 22,080 |

**FINANCIAL LEVERAGE AND COVERAGE RATIOS**

| | **2004** | 2003 | 2002 |
|---|---|---|---|
| Net debt to trailing cash flow (times) | **0.4** | 0.2 | 0.4 |
| Distributions to interest expense (times) | **86.0** | 68.0 | 37.0 |
| Net debt to distributions (times) | **0.4** | 0.3 | 0.6 |
| Net debt to net debt plus equity (%) | **12.2** | 7.0 | 10.6 |

### Sources and Uses of Funds

The following table outlines our sources and uses of funds during the past three years.

**SOURCES AND USES OF FUNDS**

| ($000s) | **2004** | 2003 | 2002 |
|---|---|---|---|
| Sources of funds | | | |
| Funds generated from operations (cash flow) | **$ 64,370** | $ 60,692 | $ 51,607 |
| Equity issued, net of costs | **—** | 10,501 | 40 |
| Change in non-cash working capital | **(212)** | 3,169 | (3,555) |
| | **$ 64,158** | $ 74,362 | $ 48,092 |
| Uses of funds | | | |
| Debt reduction (addition) | **$ (9,000)** | $ 12,000 | $ 3,000 |
| Reclamation fund | **414** | 317 | 240 |
| Capital expenditures | **5,823** | 5,894 | 2,946 |
| Net acquisition costs | **13,061** | 3,386 | 2,326 |
| Distributions to Unitholders | **53,851** | 53,024 | 39,524 |
| Change in cash | **9** | (259) | 56 |
| | **$ 64,158** | $ 74,362 | $ 48,092 |

## Acquisitions and Capital Expenditures

We completed three acquisitions for $13.1 million (net of adjustments) in 2004. These acquisitions will contribute approximately 200 boe/d to our royalty production base in 2005.

We continue to pursue opportunities to augment our production and reserves, primarily targeting royalty interests, while maintaining a disciplined valuation approach to ensure that any acquisition we complete will be accretive to our present and future Unitholders.

**ACQUISITION SUMMARY**

| ($000s) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Purchase price | $ 13,125 | $ 3,512 | $ 2,532 |
| Acquisition fee (1.5%) | 197 | 53 | 38 |
| Interest expense | — | 12 | — |
| Evaluation and legal costs | 30 | — | 48 |
| Purchase price adjustments[1] | (471) | (191) | (292) |
| Additions to petroleum and natural gas interests | 12,881 | 3,386 | 2,326 |
| Working capital | 180 | — | — |
| Net acquisition costs | $ 13,061 | $ 3,386 | $ 2,326 |

1 Net revenue from effective date to closing.

Our capital expenditure obligations are deducted from cash flow prior to the determination of distributions to Unitholders. The amount of capital expenditures to be deducted is limited to 15% of annual net cash flow from operations. As we do not incur capital expenditures on our royalty lands, our capital requirements are modest, relative to most energy trusts. In 2004, capital expenditures of $5.8 million amounted to 9% of cash flow.

For 2005, we have set a capital budget of $6.6 million, which will be funded from cash flow. The majority of this capital will be invested in development projects at Hayter and Pembina Cardium Unit No. 9 in Alberta.

**CAPITAL EXPENDITURES**

| ($000s) | 2004 | 2003 | 2002 |
|---|---|---|---|
| Development drilling | $ 3,451 | $ 4,605 | $ 1,824 |
| Plant and facilities | 2,372 | 1,289 | 1,122 |
| Total capital expenditures | $ 5,823 | $ 5,894 | $ 2,946 |

## Outstanding Units

As at March 4, 2005, there were 31,544,236 Trust Units outstanding, unchanged from the number of Trust Units outstanding as at December 31, 2004.

# INDUSTRY TRENDS

Several trends in the oil and gas industry are shaping the near term future of our business.

In 2004, $6.8 billion in new market capital flowed into the oil and gas royalty trust sector from trust unit issues, conversions and convertible debenture issues. The energy trust sector continues to exhibit strong market performance, as low interest rates and a lack of income-generating investment alternatives continue to attract investors to the sector. However, rising interest rates in 2005 may put downward pressure on trust unit prices.

Efforts by energy trusts to replace annual production declines through acquisitions have resulted in increased competition for oil and natural gas properties and related assets. This increased competition and strong commodity prices have resulted in high transaction prices.

We view continuing development on our royalty lands as an essential part of our future success. To date, we have seen no evidence to suggest that this activity is slowing. Although the Western Canadian Sedimentary Basin is maturing, drilling activity continues at a record pace. The Canadian Association of Oilwell Drilling Contractors (CAODC) reports that more than 21,500 oil and gas wells were completed in 2004, which tops the record set in 2003. The CAODC estimates that 2005 will outpace 2004 activity. As activity on our royalty lands generally mirrors industry activity, we expect that drilling on our royalty lands will likewise remain at high levels.

Crude oil markets continue to be strong. Demand remains robust, especially from China, and the outlook for 2005 is positive. Although natural gas prices tend to be more volatile than oil prices due to supply and demand factors within North America, the outlook for natural gas prices is also positive. However, the higher Canadian currency will offset a portion of the economic benefit of higher commodity prices.

Of great concern to us is the growing surplus of heavy crude and lack of upgrading capacity, which may have a significant negative impact on our price realizations due to our heavier product mix. The price differential between light and heavy crude oil depends on the relative supply and demand fundamentals of each commodity and, at times, is quite significant. Within North America, only certain refineries are configured to process heavy oil and their processing capacity is limited. In addition, bitumen production from Alberta's oil sands is expected to increase significantly over the next several years. As a result, markets for heavy oil and bitumen will be somewhat uncertain in the future. Supply and demand imbalances could result in the heavy oil price differential remaining well above historical averages.

## DISTRIBUTION OUTLOOK

Based on the assumptions in the accompanying table, we estimate that distributions in 2005 will total $1.55 per Trust Unit. This guidance will be updated quarterly throughout the year. Recognizing the cyclical nature of our industry, we caution that significant changes (positive or negative) in commodity prices (including light/heavy oil price differentials), foreign exchange rates or production rates will result in adjustments to the distribution level. It is also inherently difficult to predict activity levels on our royalty lands since we do not know the future plans of the various operators.

The regular monthly cash distribution is set at $0.12 per Trust Unit. In keeping with our stated practice, a portion of any excess income available for distribution may be directed toward repayment of long-term debt and/or working capital improvement where the board of directors considers it appropriate or necessary and extra distributions (quarterly top-ups) may be declared from time to time at the board's discretion.

**2005 DISTRIBUTION OUTLOOK AS AT FEBRUARY 16, 2005**

| | |
|---|---|
| Estimated cash distributions ($/Trust Unit) | **1.55** |
| Assumptions | |
| Average daily production, excluding acquisitions (boe/d) | **5,600** |
| Average WTI oil price (US$/bbl) | **41.00** |
| Average AECO natural gas price (Cdn$/Mcf) | **6.50** |
| Average light/heavy oil price differential (Cdn$/bbl) | **17.50** |
| Average exchange rate (US$/Cdn$) | **0.80** |
| Capital expenditures ($ millions) | **6.6** |
| Long-term debt at year end ($ millions) | **27.0** |

The following table provides an analysis of the potential impact key factors may have on distributions to Unitholders, based on our 2005 budget forecast.

**SENSITIVITY ANALYSIS**

| Variables | Change (+/–) | Estimated Change in Distributions to Unitholders | |
|---|---|---|---|
| | | ($000s) | ($/Trust Unit) |
| WTI crude oil price | US$1.00/bbl | **1,579** | **0.05** |
| Light/heavy oil price differential | Cdn$1.00/bbl | **1,264** | **0.04** |
| Natural gas price | Cdn$0.25/Mcf | **948** | **0.03** |
| Exchange rate (US$/Cdn$) | $0.01 | **632** | **0.02** |
| Interest rates | 1% | **316** | **0.01** |
| Oil and NGL production | 100 bbls/d | **1,264** | **0.04** |
| Natural gas production | 1,000 Mcf/d | **2,212** | **0.07** |

# MANAGEMENT'S AND AUDITORS' REPORTS

Management has prepared the accompanying consolidated financial statements of Freehold Royalty Trust in accordance with Canadian generally accepted accounting principles.

Management is responsible for the accuracy and integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded, transactions are properly authorized and reliable accounting records are produced for financial reporting purposes.

External auditors, KPMG LLP, were appointed by the Unitholders to perform an examination of the corporate and accounting records so as to express an opinion on the consolidated financial statements of Freehold Royalty Trust. Their examination included a review and evaluation of Freehold's internal control systems and included tests and procedures considered necessary to provide reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The board of directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. It exercises its responsibilities primarily through the audit committee, all of whose members are independent directors of Freehold Resources Ltd. The committee meets with management and the independent auditors to ensure that management's responsibilities are properly discharged.

D.J. Sandmeyer

David J. Sandmeyer
President & Chief Executive Officer
February 16, 2005

D.N. Holowisky

Joseph N. Holowisky
Vice President, Finance & Administration,
Chief Financial Officer and Secretary

**To the Unitholders of Freehold Royalty Trust**

We have audited the consolidated balance sheets of Freehold Royalty Trust as at December 31, 2004 and 2003, and the consolidated statements of income and accumulated earnings and cash flows for the years ended December 31, 2004 and 2003. These consolidated financial statements are the responsibility of Freehold's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Freehold as at December 31, 2004 and 2003, and the results of its operations and its cash flows for the years ended December 31, 2004 and 2003, in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KMPG LLP
Chartered Accountants
Calgary, Canada
February 16, 2005

# CONSOLIDATED BALANCE SHEETS

| ($000s) | December 31 2004 | 2003 (restated - note 2) |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash | $ 66 | $ 57 |
| Accounts receivable | 12,797 | 11,629 |
| | 12,863 | 11,686 |
| Reclamation fund (note 6) | 1,646 | 1,289 |
| Petroleum and natural gas interests (note 3) | 193,492 | 198,897 |
| | $ 208,001 | $ 211,872 |
| **Liabilities and Unitholders' Equity** | | |
| Current liabilities: | | |
| Distributions payable to Unitholders | $ 3,785 | $ 3,145 |
| Accounts payable and accrued liabilities | 4,950 | 4,174 |
| | 8,735 | 7,319 |
| Asset retirement obligation (note 6) | 3,937 | 3,606 |
| Long-term debt (note 5) | 27,000 | 18,000 |
| Future income tax liability (note 10) | 3,507 | 1,955 |
| Unitholders' equity: | | |
| Unitholders' capital (note 7) | 298,936 | 297,508 |
| Accumulated earnings | 164,100 | 127,208 |
| Accumulated distributions | (298,214) | (243,724) |
| | $ 208,001 | $ 211,872 |

See accompanying notes to consolidated financial statements.

Approved on behalf of Freehold Royalty Trust by Freehold Resources Ltd., as Administrator:

William W. Siebens
DIRECTOR

D. Nolan Blades
DIRECTOR

# CONSOLIDATED STATEMENTS OF INCOME AND ACCUMULATED EARNINGS

| | | Years Ended December 31 |
|---|---|---|
| ($000s, except per unit data) | **2004** | 2003 |
| | | (restated - note 2) |
| Revenue: | | |
| Royalty income and working interest sales | **$ 78,491** | $ 73,166 |
| Royalty expense (net of ARC) | **(2,977)** | (3,197) |
| | **75,514** | 69,969 |
| Other expenses: | | |
| Operating | **5,860** | 5,190 |
| General and administrative | **3,502** | 2,866 |
| Interest on long-term debt | **635** | 778 |
| Depletion and depreciation | **25,661** | 21,860 |
| Accretion of asset retirement obligation (note 6) | **232** | 214 |
| Management fee (note 8) | **1,428** | 1,235 |
| | **37,318** | 32,143 |
| Net income before taxes | **38,196** | 37,826 |
| Income and capital taxes (note 10) | **1,147** | 443 |
| Future income tax provision (note 10) | **157** | 305 |
| Net income | **36,892** | 37,078 |
| Accumulated earnings - beginning of period, as previously reported | **127,309** | 90,283 |
| Retroactive effect of change in accounting policy (note 2) | **(101)** | (153) |
| Accumulated earnings - beginning of period, as restated | **127,208** | 90,130 |
| Accumulated earnings - end of period, as restated | **$ 164,100** | $ 127,208 |
| Net income per Trust Unit, basic and diluted | **$ 1.17** | $ 1.19 |

See accompanying notes to consolidated financial statements.

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Years Ended December 31 | |
|---|---|---|
| ($000s) | **2004** | 2003 (restated - note 2) |
| Cash provided by (used in): | | |
| Operating: | | |
| Net income | **$ 36,892** | $ 37,078 |
| Items not involving cash: | | |
| Depletion and depreciation | **25,661** | 21,860 |
| Future income tax provision | **157** | 305 |
| Accretion of asset retirement obligation | **232** | 214 |
| Trust Units issued in lieu of management fee | **1,428** | 1,235 |
| Funds generated from operations | **64,370** | 60,692 |
| Expenditures on reclamation | **(57)** | (34) |
| Changes in non-cash working capital (note 11) | **(212)** | 3,169 |
| | **64,101** | 63,827 |
| Financing: | | |
| Trust Units issued upon exercise of options | **—** | 10,501 |
| Long-term debt | **9,000** | (12,000) |
| Distributions paid | **(53,851)** | (53,024) |
| | **(44,851)** | (54,523) |
| Investing: | | |
| Corporate acquisition (note 4) | **(3,048)** | — |
| Property and royalty acquisitions | **(10,013)** | (3,386) |
| Development expenditures | **(5,823)** | (5,894) |
| Increase in reclamation fund | **(357)** | (283) |
| | **(19,241)** | (9,563) |
| Increase (decrease) in cash | **9** | (259) |
| Cash, beginning of year | **57** | 316 |
| Cash, end of year | **$ 66** | $ 57 |

See accompanying notes to consolidated financial statements.

# NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2004 and 2003.

## BASIS OF PRESENTATION

Freehold Royalty Trust (the Trust) is an open-end investment trust formed under the laws of the Province of Alberta pursuant to a Trust Indenture dated September 30, 1996 as amended from time to time. The Trust holds royalty interests directly and a 99% royalty interest in the funds generated by its wholly owned subsidiary, Freehold Resources Ltd. (Resources). Resources was incorporated on June 3, 1996 and derives its income from certain petroleum and natural gas working interest properties.

These consolidated financial statements include the accounts of the Trust and Resources. All inter-entity transactions have been eliminated.

## 1. SIGNIFICANT ACCOUNTING POLICIES

### (a) Petroleum and Natural Gas Interests:

The Trust follows the full cost method of accounting.

All costs of acquiring, exploring for and developing oil and gas and related reserves are capitalized. Such costs include land acquisition, geological and geophysical, carrying charges of unproved properties, costs of drilling both productive and non-productive wells, directly related general and administrative costs and asset retirement costs. Costs are reduced by proceeds from the sale of oil and gas properties and by government grants. Gains and losses are not recognized upon disposition of oil and gas properties unless such a disposition would alter the rate of depletion by 20% or more.

### (b) Ceiling Test:

Petroleum and natural gas interests are evaluated in each reporting period to determine that the carrying amount is recoverable and does not exceed the fair value of the properties.

The carrying amount is assessed to be recoverable when the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount exceeds the sum of the discounted cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved interests and the cost of major development projects. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

### (c) Depletion:

Oil and gas interests and royalty interests, including the costs of production equipment, future capital costs associated with proved reserves and asset retirement costs, are depleted on the unit-of-production method based on estimated proved oil and gas reserves before royalties. Reserves are converted to equivalent units on the basis of relative energy content.

### (d) Asset Retirement Obligations:

The Trust recognizes the fair value of an asset retirement obligation in the period in which it is incurred and when a reasonable estimate of the fair value can be made. The fair value of the estimated asset retirement obligation is recorded as a long-term liability, with a corresponding increase in the carrying value of the asset. The capitalized amount is depleted on a unit-of-production method over the life of the reserves. In periods subsequent to initial measurement, the passage of time results in liability changes and the amount of accretion is charged against current period income. The liability is also adjusted for revisions to previously used estimates.

**(e) Income and Other Taxes:**

The Trust is a taxable trust under the *Income Tax Act* (Canada) and it distributes substantially all of its taxable income to its Unitholders. The tax deductions received by the Trust for the distributions to Unitholders represent an exemption from taxation equivalent to the Trust's earnings. In addition, the Trust is exempt from future income taxes because it is contractually committed to distribute all of its income to its Unitholders.

Resources follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs. Resources can deduct royalty payments to the Trust in determining taxable income and is generally liable for income taxes on its 1% residual interest.

**(f) Cash:**

Cash includes cash on deposit and highly liquid investments with original maturities of three months or less.

**(g) Measurement Uncertainty:**

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities and the reported amounts of revenue and expenses during the reporting period. Actual results could differ as a result of using estimates.

**(h) Unit Based Compensation Plans:**

In accordance with the Trust's Unit Option Plan, Trust Units are granted to the independent directors of Resources and to the Manager, Rife Resources Management Ltd.

The Trust accounts for its Unit Option Plan using the fair value method. Under this method, the Trust records a compensation expense over the vesting period of the plan, with a corresponding increase to contributed surplus. Upon exercise of the options, consideration paid, together with the amount previously recognized in contributed surplus, is recorded as an increase in Unitholders' capital.

**(i) Earnings Per Unit:**

Basic units outstanding are the weighted average number of units outstanding for each period. Diluted units outstanding are calculated using the treasury stock method, which assumes that any proceeds received from options with a market value in excess of option price would be used to buy back units at the average market price for the period.

## 2. CHANGES IN ACCOUNTING POLICY

**(a) Asset Retirement Obligations:**

On January 1, 2004, the Trust adopted new Canadian accounting standards for asset retirement obligations. This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

Previously, the Trust recognized a provision for estimated future abandonment and site restoration costs provided for on the unit-of-production method over the remaining proved reserves. The annual charge was expensed as a provision for future site restoration, with abandonment and site restoration expenditures charged to the accumulated provision as incurred.

This change in accounting policy resulted in the following increases (decreases) to the Trust's 2003 financial results:

| ($000s) | |
|---|---|
| Net income | $ 52 |
| Petroleum and natural gas interests, net of accumulated depletion and depreciation | 1,732 |
| Asset retirement obligation | 3,606 |
| Provision for future site restoration | (1,773) |

The opening adjustment to 2004 Unitholders' equity was a reduction of $101,000 (2003 - $153,000). This reflects the cumulative impact of accretion and depletion expense, net of the previously recorded cumulative site restoration provision.

**(b) Full Cost Accounting - Ceiling Test:**

Effective January 1, 2004, the Trust has adopted the recommendations of the revised Canadian guideline for the full cost method of oil and gas accounting, as outlined in note 1(b).

Prior to January 1, 2004, the ceiling test amount was the sum of the undiscounted cash flows expected from the production of proved reserves, the lower of cost or market of unproved properties and the cost of major development projects less estimated future costs for administration, financing and site restoration. The cash flows were estimated using period end prices and costs.

There were no changes to any amounts reported in the consolidated financial statements as a result of adopting this revised guideline.

## 3. PETROLEUM AND NATURAL GAS INTERESTS

| ($000s) | **2004** | 2003 |
|---|---|---|
| Petroleum and natural gas interests | **$ 374,411** | $ 354,155 |
| Accumulated depletion and depreciation | **(180,919)** | (155,258) |
| Petroleum and natural gas interests, net | **$ 193,492** | $ 198,897 |

The depletion calculation excluded the cost of unproved lands valued at $2.7 million at December 31, 2004 (2003 – $3 million).

The Trust's ceiling test calculation, performed at December 31, 2004, resulted in no impairment loss. The future prices used by the Trust in estimating cash flows were based on forecasts by an independent reserves evaluator, adjusted for the Trust's quality, transportation, and contract differences. The following table summarizes the benchmark prices used in the calculation.

| Year | WTI Oil (US$/bbl) | Foreign Exchange Rate | Edmonton Par Crude Oil (Cdn$/bbl) | AECO Gas (Cdn$/MMBtu) |
|---|---|---|---|---|
| 2005 | 44.29 | 0.84 | 51.25 | 6.97 |
| 2006 | 41.60 | 0.84 | 48.03 | 6.66 |
| 2007 | 37.09 | 0.84 | 42.64 | 6.21 |
| 2008 | 33.46 | 0.84 | 38.31 | 5.73 |
| 2009 | 31.84 | 0.84 | 36.36 | 5.37 |
| Average annual increase, thereafter | 1.5% | | 1.5% | 1.5% |

## 4. BUSINESS COMBINATION

On July 31, 2004, the Trust acquired all of the issued and outstanding shares of Ventana Ventures Inc., a private corporation, for cash. Ventana was the owner of producing royalty income properties in the Peace River area of Alberta. Results of operations for the acquisition have been included in the Trust's financial results for the period from August 1, 2004 onward.

The transaction was accounted for by the purchase method with fair values as follows:

| ($000s) | |
|---|---|
| Net assets acquired: | |
| Petroleum and natural gas interests | $ 2,868 |
| Working capital | 180 |
| | $ 3,048 |

## 5. LONG-TERM DEBT

The Trust has a $50 million committed production facility on which $27 million was drawn at December 31, 2004 (2003 – $18 million). The facility is secured by a General Security Agreement from the Trust and Resources, providing a first priority security interest in both Resources' and the Trust's assets and specific assignment of royalties. A demand debenture is pledged from both Resources and the Trust in the amount of $100 million, conveying a first floating charge over all property. The facility is structured as a one-year committed revolving credit facility, extendible annually. In the event that the lender does not consent to such extension, the revolving credit facility will convert to a three-year non-revolving amortizing term loan with principal payments due quarterly. At December 31, 2004 and 2003, the entire amount outstanding under the production facility is presented as long term based on the Trust's ability to refinance any current amount with the undrawn portion of the facility.

In addition, the Trust has available a $15 million demand operating facility and a US$10 million swap facility, which was undrawn at December 31, 2004 and 2003. The facilities have security similar to that of the production facility with any amounts outstanding payable on demand.

Borrowings under the facility bear interest at the Bank's prime lending rate, bankers' acceptance or LIBOR rates plus applicable margins, ranging from 90 to 165 basis points.

## 6. ASSET RETIREMENT OBLIGATIONS

The Trust has no asset retirement obligations on its royalty income properties. The Trust's asset retirement obligation results from its responsibility to abandon and reclaim its net share of all working interest properties. The net present value of the Trust's total asset retirement obligation is estimated to be $3.9 million, with the undiscounted value being $9.9 million. Payments to settle the obligations are expected to occur continuously over the next 50 years, with the majority of obligations being more than 15 years away. A credit adjusted risk-free rate of 6.25% was used to calculate the present value of the asset retirement obligation.

| | December 31 | |
|---|---|---|
| ($000s) | **2004** | 2003 |
| Balance, beginning of period | **$ 3,606** | $ 3,289 |
| Liabilities incurred | **156** | 137 |
| Liabilities settled | **(57)** | (34) |
| Accretion expense | **232** | 214 |
| Balance, end of period | **$ 3,937** | $ 3,606 |

A reclamation fund, consisting of cash invested in an interest-bearing account, has been established and is funded by quarterly cash payments. All liabilities settled during the periods are paid from the reclamation fund.

## 7. UNITHOLDERS' CAPITAL

The Trust has authorized an unlimited number of Trust Units of which 31,544,236 (2003 – 31,454,236) were issued at December 31, 2004.

**TRUST UNITS ISSUED**

| | **2004** | | 2003 | |
|---|---|---|---|---|
| | **Number** | **Amount** ($000s) | Number | Amount ($000s) |
| Balance, beginning of year | **31,454,236** | **$ 297,508** | 30,225,236 | $ 285,772 |
| Issued upon exercise of options | **—** | **—** | 1,139,000 | 10,501 |
| Issued in lieu of management fee | **90,000** | **1,428** | 90,000 | 1,235 |
| Balance, end of year | **31,544,236** | **$ 298,936** | 31,454,236 | $ 297,508 |

The Trust has reserved 820,000 Trust Units pursuant to a Trust Unit Option Plan. Options to purchase Trust Units may be issued to the independent directors of Resources or to the Manager. As at December 31, 2004 and 2003, no options to purchase Trust Units were outstanding.

The Trust has reserved 500,000 Trust Units pursuant to its Management Agreement with the Manager, of which 264,236 have been issued to date.

The weighted average number of Trust Units outstanding for 2004 was 31,488,355 (2003 – 31,164,161).

## 8. RELATED PARTY TRANSACTIONS

The Manager provides certain services for a fee based on a specified number of Trust Units per quarter, pursuant to a Management Agreement which has a term of three years and will be renewed on November 26, 2007 unless terminated. During 2004, the management fee charged was 90,000 Trust Units with an ascribed value of $1,428,000 (2003 – 90,000 Trust Units with an ascribed value of $1,235,000).

During the year, the Manager charged the Trust $2,579,000 (2003 – $2,274,000) in general and administrative costs. At December 31, 2004, there was $393,000 (2003 – $343,000) included in accounts payable relating to these costs.

The Manager also earns a fee of 1.5% of the purchase price of oil and gas properties acquired by the Trust. During 2004, the Manager acquired $13,125,000 (purchase price) of properties on behalf of the Trust (2003 – $3,512,000) and was paid $197,000 (2003 – $53,000) relating to these acquisitions. This fee is charged to petroleum and natural gas interests as part of the properties acquired.

## 9. DISTRIBUTIONS TO UNITHOLDERS

Distributions to Unitholders are declared on a monthly basis, with payments to be made on the 15th day following the month end.

The following table shows distributions declared to Unitholders as at December 31:

| ($000s, except per unit data) | 2004 | 2003 |
|---|---|---|
| Funds generated from operations | $ 64,370 | $ 60,692 |
| Reclamation fund contributions | (414) | (317) |
| Development expenditures[1] | (5,823) | (5,894) |
| Debt addition (repayment from cash flow) | 9,000 | (1,499) |
| Corporate acquisition | (3,048) | — |
| Property and royalty acquisitions | (10,013) | (3,386) |
| Changes in working capital | 418 | 3,553 |
| Distributions to Unitholders | 54,490 | 53,149 |
| Accumulated distributions, beginning of year | 243,724 | 190,575 |
| Accumulated distributions, end of year | $ 298,214 | $ 243,724 |
| Distributions per Trust Unit | $ 1.73 | $ 1.70 |
| Accumulated distributions per Trust Unit, beginning of year | 8.55 | 6.85 |
| Accumulated distributions per Trust Unit, end of year | $ 10.28 | $ 8.55 |

1 The amount of capital expenditures is limited to 15% of annual net cash flow from operations, unless additional capital expenditures are financed with borrowings, additional issuances of Trust Units or proceeds from the disposition of assets.

## 10. INCOME TAXES

Resources uses the liability method of accounting for income taxes, as described in note 1. The provision for income taxes in the financial statements differs from the result which would have been obtained by applying the combined federal and provincial tax rate to the Trust's earnings before income taxes. This difference results from the following items:

| ($000s) | 2004 | 2003 |
|---|---|---|
| Earnings before income taxes and capital taxes | $ 38,196 | $ 37,774 |
| Combined federal and provincial tax rate | 39.2% | 41.0% |
| Computed expected income tax expense | $ 14,983 | $ 15,478 |
| Increase (decrease) in income tax resulting from: | | |
| Non-taxable earnings of the Trust | (13,528) | (13,881) |
| Non-deductible Crown charges | 204 | 10 |
| Resource allowance | (491) | (417) |
| Benefit of future rate reductions | (78) | (358) |
| Changes in enacted tax rates | (58) | (54) |
| Benefit of provincial royalty tax deductions | — | (139) |
| Prior year's charges in current expense | 155 | — |
| Capital taxes | 116 | 103 |
| Other | 1 | 6 |
| Total income and capital taxes | $ 1,304 | $ 748 |

Total income taxes are comprised of:

| ($000s) | 2004 | 2003 |
|---|---|---|
| Current income and capital taxes | $ 1,147 | $ 443 |
| Future taxes | 157 | 305 |
| Total income and capital taxes | $ 1,304 | $ 748 |

The components of Resources' future income taxes at December 31 are as follows:

| ($000s) | 2004 | 2003 |
|---|---|---|
| Future income tax liabilities: | | |
| Oil and natural gas properties | $ 4,831 | $ 2,567 |
| Future income tax assets: | | |
| Abandonment costs | (1,324) | (612) |
| Future income taxes | $ 3,507 | $ 1,955 |

## 11. SUPPLEMENTAL CASH FLOW DISCLOSURE

### CHANGES IN NON-CASH WORKING CAPITAL BALANCE

| ($000s) | 2004 | 2003 |
|---|---|---|
| Accounts receivable | $ (1,168) | $ 1,814 |
| Accounts payable and accrued liabilities | 776 | 1,355 |
| Working capital from corporate acquisition | 180 | — |
| | $ (212) | $ 3,169 |

### CASH EXPENSES PAID

| ($000s) | 2004 | 2003 |
|---|---|---|
| Interest | $ 643 | $ 712 |
| Taxes | 808 | 440 |

## 12. COMPARATIVE FIGURES

Certain comparative figures have been restated to conform to the current year's financial presentation.

# NINE-YEAR HISTORICAL REVIEW

| | 2004 | 2003 | 2002 | 2001 | 2000 | 1999 | 1998 | 1997 | 1996[1] |
|---|---|---|---|---|---|---|---|---|---|
| **Financial** | | | | | | | | | |
| ($000s, except as noted) | | | | | | | | | |
| Gross revenue | **78,491** | 73,166 | 63,143 | 61,885 | 64,500 | 36,355 | 24,839 | 39,953 | 4,056 |
| Net income[2] | **36,892** | 37,078 | 27,529 | 27,304 | 31,758 | 8,714 | (9,278) | 3,045 | 1,057 |
| Per Trust Unit ($) | **1.17** | 1.19 | 0.91 | 0.95 | 1.19 | 0.33 | (0.35) | 0.12 | 0.04 |
| Distributions | **54,490** | 53,149 | 39,530 | 45,264 | 35,226 | 20,757 | 17,186 | 29,081 | 3,532 |
| Per Trust Unit ($) | **1.73** | 1.70 | 1.31 | 1.56 | 1.32 | 0.78 | 0.65 | 1.10 | 0.13 |
| Capital expenditures | **5,823** | 5,894 | 2,946 | 2,992 | 5,161 | 940 | 1,790 | 2,613 | 13 |
| Acquisitions | **13,061** | 3,386 | 2,326 | 29,707 | 5,326 | — | — | 27,407 | — |
| Long-term debt | **27,000** | 18,000 | 30,000 | 33,000 | 38,000 | 39,288 | 39,288 | 38,175 | 10,719 |
| Unitholders' equity | **164,822** | 180,992 | 185,326 | 196,317 | 182,898 | 185,742 | 197,346 | 233,261 | 248,464 |
| **Operating** | | | | | | | | | |
| Production | | | | | | | | | |
| Oil (bbls/d) | **3,594** | 3,688 | 3,926 | 3,873 | 3,353 | 2,921 | 3,208 | 3,566 | 3,016 |
| NGL (bbls/d) | **283** | 317 | 288 | 354 | 327 | 302 | 339 | 347 | 340 |
| Natural gas (MMcf/d) | **10.3** | 10.9 | 10.7 | 11.2 | 11.0 | 11.2 | 11.9 | 15.5 | 13.5 |
| Oil equivalent (boe/d) | **5,588** | 5,817 | 6,004 | 6,086 | 5,523 | 5,082 | 5,531 | 6,493 | 5,602 |
| Potash (tonnes/d) | **7.6** | 7.6 | 7.8 | 7.9 | 10.9 | 14.2 | 15.3 | 12.5 | 14.0 |
| Average sales price | | | | | | | | | |
| Oil ($/bbl) | **38.08** | 32.77 | 31.25 | 24.42 | 32.98 | 21.82 | 12.91 | 19.22 | 25.55 |
| NGL ($/bbl) | **37.29** | 30.95 | 25.09 | 29.91 | 32.81 | 16.94 | 13.82 | 19.02 | 19.88 |
| Natural gas ($/Mcf) | **6.28** | 6.18 | 3.81 | 5.64 | 4.71 | 2.48 | 1.91 | 1.79 | 1.72 |
| Oil equivalent ($/boe) | **37.91** | 34.01 | 28.44 | 27.63 | 31.39 | 18.99 | 12.45 | 15.84 | 19.11 |
| Potash ($/tonne) | **167.37** | 133.36 | 143.33 | 153.98 | 146.72 | 157.56 | 147.72 | 114.29 | 105.00 |
| Operating netback ($/boe) | **34.05** | 30.51 | 25.43 | 24.30 | 28.26 | 17.10 | 9.94 | 14.63 | 18.38 |
| Undeveloped land (gross acres) | **291,729** | 242,205 | 235,062 | 237,443 | 140,896 | 136,036 | 132,609 | 77,906 | 49,000 |
| Reserves (Mboe)[3] | **21,163** | 22,052 | 26,813 | 28,177 | 28,150 | 29,062 | 29,952 | 30,809 | 29,437 |
| Reserve life index (years) | **10.6** | 11.0 | 12.2 | 12.7 | 14.0 | 15.7 | 14.8 | 13.0 | 14.4 |
| **Trust Unit** | | | | | | | | | |
| High ($) | **18.42** | 17.19 | 11.35 | 10.10 | 9.50 | 6.90 | 9.80 | 11.85 | 12.70 |
| Low ($) | **14.02** | 10.50 | 9.00 | 8.00 | 5.60 | 4.13 | 4.15 | 8.40 | 11.15 |
| Close ($) | **17.45** | 16.35 | 10.88 | 9.20 | 8.70 | 5.95 | 4.43 | 9.10 | 11.20 |
| Volume (000s) | **11,567** | 10,970 | 7,323 | 8,162 | 6,752 | 5,782 | 9,686 | 11,392 | 12,943 |
| Outstanding, end of year (millions) | **31.5** | 31.5 | 30.2 | 30.1 | 26.7 | 26.6 | 26.6 | 26.5 | 26.4 |
| Weighted average (millions) | **31.5** | 31.2 | 30.2 | 28.8 | 26.7 | 26.6 | 26.5 | 26.4 | 26.4 |

1 37-day period from November 25 to December 31, 1996.

2 2003 and prior years restated.

3 The 2004 and 2003 reserves data is not directly comparable to data for the years 1996 through 2002 due to new reserve definitions and evaluation methodology that came into effect in 2003. Reserves for 2004 and 2003 were evaluated under National Instrument 51-101 and are reported as net proved plus probable reserves. Previously, reserves were evaluated under National Policy 2-B and reported as gross (before royalties) proved plus half probable (established) reserves.

# UNITHOLDER TAX INFORMATION

**The following information is provided for general information only. Unitholders are advised to consult their personal tax advisors with respect to their particular circumstances.**

## FOR CANADIAN RESIDENTS

For purposes of the *Income Tax Act* (Canada), Freehold Royalty Trust is treated as a mutual fund trust. Each year, we file a T3 income tax return with the taxable income allocated to and made taxable in the hands of Unitholders. This taxable income is allocated, on T3 supplementary forms, to each Unitholder who received distributions in that taxation year. The T3 slip will report only the other income component in Box 26. This income is taxed as ordinary income. The portion deemed return of capital reduces the Unitholder's adjusted cost base in the Units and should be included in the computation of capital gain (or loss) at the time of disposition.

**2004 TAX INFORMATION**

| Record Date | Payment Date | Taxable Amount Box 26 (Other Income) | Tax-Deferred Amount (Return of Capital) | **Total Distribution Paid Cdn$** |
|---|---|---|---|---|
| December 31, 2003 | January 15, 2004 | $ 0.0680 | $ 0.0320 | **$ 0.10** |
| January 31, 2004 | February 15, 2004 | 0.0680 | 0.0320 | **0.10** |
| February 29, 2004 | March 15, 2004 | 0.1156 | 0.0544 | **0.17** |
| March 31, 2004 | April 15, 2004 | 0.0680 | 0.0320 | **0.10** |
| April 30, 2004 | May 15, 2004 | 0.0680 | 0.0320 | **0.10** |
| May 31, 2004 | June 15, 2004 | 0.1360 | 0.0640 | **0.20** |
| June 30, 2004 | July 15, 2004 | 0.0680 | 0.0320 | **0.10** |
| July 31, 2004 | August 15, 2004 | 0.0680 | 0.0320 | **0.10** |
| August 31, 2004 | September 15, 2004 | 0.1700 | 0.0800 | **0.25** |
| September 30, 2004 | October 15, 2004 | 0.0816 | 0.0384 | **0.12** |
| October 31, 2004 | November 15, 2004 | 0.0816 | 0.0384 | **0.12** |
| November 30, 2004 | December 15, 2004 | 0.1700 | 0.0800 | **0.25** |
| **Total paid during the 2004 taxation year** | | $ 1.1628 | $ 0.5472 | **$ 1.71** |

### Adjusted Cost Base Calculation for Capital Gains Purposes

Unitholders are required to reduce the adjusted cost base (ACB) of their Trust Units by the amount equal to any distributions received in the form of return of capital (the tax-deferred portion of distributions received). Unitholders should maintain a record of all distributions that are classified as partially or entirely a return of capital distribution while holding Trust Units. For investors in the $10 per Trust Unit initial public offering in November 1996, the ACB of Trust Units still held as at December 31, 2004 is $3.5284 per Trust Unit, taking into account the cumulative return of capital of $6.4716 as provided in the following table.

**HISTORICAL TAX INFORMATION**

| Taxation Year[1] | Taxable Amount (Other Income) Per Unit[2] | Tax Deferred Amount (Return of Capital) Per Unit[3] | Taxable Percentage | Tax Deferred Percentage | Total Distribution Paid Cdn$ |
|---|---|---|---|---|---|
| **2004** | **$ 1.1628** | **$ 0.5472** | **68%** | **32%** | **$ 1.71** |
| 2003 | 1.1730 | 0.5270 | 69% | 31% | 1.70 |
| 2002 | 0.7598 | 0.5502 | 58% | 42% | 1.31 |
| 2001 | 0.5928 | 0.9672 | 38% | 62% | 1.56 |
| 2000 | 0.0000 | 1.2900 | 0% | 100% | 1.29 |
| 1999 | 0.0000 | 0.7600 | 0% | 100% | 0.76 |
| 1998 | 0.0000 | 0.8500 | 0% | 100% | 0.85 |
| 1997 | 0.0000 | 0.9800 | 0% | 100% | 0.98 |
| **Total** | $ 3.6884 | $ 6.4716 | | | **$ 10.16** |

1 For income tax purposes, only cash payments received in each calendar year are subject to Canadian income tax.
2 As at December 31, 2004, we have the benefit of $161 million of income tax accounts to reduce the taxable portion of future distributions.
3 The tax-deferred amount reduces the adjusted cost base of a Unitholder's investment in Trust Units.

## FOR NON-RESIDENTS OF CANADA

Unitholders who are not residents of Canada for income tax purposes are encouraged to seek advice from a qualified tax advisor in their country of residence for the tax treatment of distributions.

Monthly income distributions payable to non-residents of Canada are normally subject to a withholding tax of 25% as prescribed by the *Income Tax Act* (Canada). This withholding tax may be reduced in accordance with reciprocal tax treaties. In the case of the Tax Treaty between Canada and the U.S., the withholding tax for U.S. residents is prescribed at 15%. The non-resident Unitholder will have been subject to tax withholdings in excess of that required based on the taxable portion of their distribution for Canadian purposes. A non-resident can apply for a refund of this excess tax paid by completing Form NR7-R, Application of Refund of Non-Resident Tax Withheld. This form has to be received by the Canada Revenue Agency no later than two years from the end of the calendar year in which the tax was remitted.

### United States Tax Information for Unitholders Resident in the United States

For U.S. purposes only, Freehold Royalty Trust is considered a corporation and therefore the full amount of the distribution is considered a dividend. At this time, we do not perform a current and accumulated earnings and profits calculation; therefore, distributions are 100% taxable to U.S. residents.

*The U.S. Jobs and Growth Tax Relief Reconciliation Act of 2003* (the Act) was signed into law on May 28, 2003. The Act effectively reduces the U.S. federal income tax rate on qualified dividend income, received January 1, 2003 through December 31, 2008, to a maximum of 15%. Qualified dividend income is defined as dividends received during the taxation year from domestic U.S. corporations and "qualified foreign corporations". The term "qualified foreign corporation" excludes, among other things, a passive foreign investment company (PFIC). Therefore, dividends from a PFIC are not eligible for the above-noted lower rate of tax. Based on legal and tax advice we have obtained, as the majority of our revenue is derived from non-operated royalty interests, Freehold Royalty Trust may be considered a PFIC for U.S. tax purposes and therefore may not be a qualified foreign corporation for U.S. federal income tax purposes under the Act. As such, our distributions may not be eligible for the lower U.S. tax rate outlined above.

**2004 DISTRIBUTIONS IN U.S. DOLLARS**

| Record Date | Payment Date | Total Distribution Paid in Cdn$ | Cdn$/US$ Exchange Rate | **Total Distribution Paid in US$** |
|---|---|---|---|---|
| December 31, 2003 | January 15, 2004 | $ 0.10 | 1.2924 | **$ 0.077375** |
| January 31, 2004 | February 15, 2004 | 0.10 | 1.3264 | **0.075392** |
| February 29, 2004 | March 15, 2004 | 0.17 | 1.3401 | **0.126856** |
| March 31, 2004 | April 15, 2004 | 0.10 | 1.3105 | **0.076307** |
| April 30, 2004 | May 15, 2004 | 0.10 | 1.3707 | **0.072955** |
| May 31, 2004 | June 15, 2004 | 0.20 | 1.3634 | **0.146692** |
| June 30, 2004 | July 15, 2004 | 0.10 | 1.3404 | **0.074605** |
| July 31, 2004 | August 15, 2004 | 0.10 | 1.3292 | **0.075233** |
| August 31, 2004 | September 15, 2004 | 0.25 | 1.3167 | **0.189869** |
| September 30, 2004 | October 15, 2004 | 0.12 | 1.2639 | **0.094944** |
| October 31, 2004 | November 15, 2004 | 0.12 | 1.2207 | **0.098304** |
| November 30, 2004 | December 15, 2004 | 0.25 | 1.1904 | **0.210013** |
| **Total paid during the 2004 taxation year** | | $ 1.71 | | **$ 1.318545** |

# UNITHOLDER INFORMATION

**Please visit *www.freeholdtrust.com* for annual and quarterly reports, news releases, investor presentations, a glossary of oil and gas terms, FRU.UN trading history and information on cash distributions and Unitholder taxation.**

## Distribution Policy and Dates

We make monthly distributions, the amounts of which are determined by the board of directors and subject to change depending upon the business environment. Record dates are the end of each month, and payment dates are the fifteenth day of the following month. Regular monthly distributions are supplemented by quarterly top-ups when excess funds are available.

## Unitholder Plans

**Direct Deposit Plan:** A Direct Deposit Plan is in place to provide Unitholders who have Canadian bank accounts with a method of receiving cash distributions as a direct deposit into their bank accounts.

**Distribution Reinvestment Plan (DRIP):** A DRIP is in place to provide Unitholders who are residents of Canada with a method of reinvesting cash distributions into new Trust Units.

**U.S. Currency Payment Plan:** Unitholders may elect to receive their distribution payments in U.S. funds.

## Transfer Agent

For information about distribution cheques, Trust Unit certificates, transfers, duplicate mailings and address changes, please contact:

Computershare Trust Company of Canada
600, 530 – 8 Avenue S.W.
Calgary, Alberta T2P 3S8
Telephone: (403) 267-6555
Fax: (403) 267-6592
Toll Free: 1-888-267-6555
Email: service@computershare.com

## 2005 Reporting Calendar

**Feb. 16:** Fourth quarter and 2004 year-end results
**May 11:** First quarter results
**Aug. 10:** Second quarter results
**Nov. 9:** Third quarter results

## Annual Meeting of Unitholders

The Annual Meeting of Unitholders will be held on Wednesday, May 11, 2005, at 3:30 p.m. in the Lecture Theatre, Sunlife Plaza Conference Centre, Plus 15 (2nd level), 140 – 4 Avenue S.W., Calgary, Alberta.

## Abbreviations

| | |
|---|---|
| **AECO:** | reference pricing point for gas located at a gas storage facility near the Alberta/Saskatchewan border |
| **API:** | American Petroleum Institute |
| **bbl and bbls:** | barrel and barrels, respectively, each barrel representing 34.972 imperial gallons or 42 US gallons |
| **bbls/d:** | barrels per day |
| **boe:** | barrels of oil equivalent converting six thousand cubic feet (6 mcf) of natural gas to one barrel of oil equivalent and one barrel of natural gas liquids to one barrel of oil equivalent. Sulphur volumes are not included. The 6:1 boe ratio approximates an equivalent energy value at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation. |
| **boe/d:** | barrels of oil equivalent per day |
| **Mbbls:** | one thousand barrels |
| **Mboe:** | one thousand barrels of oil equivalent |
| **MMbbls:** | one million barrels |
| **MMboe:** | one million barrels of oil equivalent |
| **MMBtu:** | one million British Thermal Units |
| **Mcf:** | one thousand cubic feet |
| **Mcf/d:** | one thousand cubic feet per day |
| **MMcf:** | one million cubic feet |
| **MMcf/d:** | one million cubic feet per day |
| **Mtonne:** | one thousand tonnes |
| **NGL:** | natural gas liquids |
| **WTI:** | West Texas Intermediate |

**TRADING PERFORMANCE**

| | 2004 | | | | 2003 | | | |
|---|---|---|---|---|---|---|---|---|
| | **Q4** | **Q3** | **Q2** | **Q1** | Q4 | Q3 | Q2 | Q1 |
| High ($) | **18.42** | **16.97** | **15.80** | **16.30** | 17.19 | 13.85 | 13.48 | 11.85 |
| Low ($) | **15.75** | **14.57** | **14.65** | **14.02** | 13.11 | 12.81 | 11.20 | 10.50 |
| Close ($) | **17.45** | **16.25** | **15.00** | **14.75** | 16.35 | 13.70 | 13.05 | 11.78 |
| Volume (000s) | **4,252** | **1,768** | **3,149** | **2,399** | 2,506 | 2,991 | 2,447 | 3,025 |

# CORPORATE INFORMATION

## Head Office

Freehold Resources Ltd.
Freehold Royalty Trust
400, 144 – 4 Avenue S.W.
Calgary, Alberta T2P 3N4
Telephone: (403) 221-0802
Fax: (403) 221-0888
www.freeholdtrust.com

## Stock Exchange Listing

Toronto Stock Exchange
Symbol: FRU.UN

## Trustee and Transfer Agent

Computershare Trust Company of Canada
Calgary, Alberta and Toronto, Ontario

## Legal Counsel

Burnet, Duckworth & Palmer LLP
Calgary, Alberta

## Auditors

KPMG LLP
Calgary, Alberta

## Banker

Canadian Imperial Bank of Commerce
Calgary, Alberta

## Evaluation Engineers

Trimble Engineering Associates Ltd.
Calgary, Alberta

## Board of Directors

William W. Siebens[2]
D. Nolan Blades[1, 2, 3]
Harry S. Campbell, Q.C.[3]
Tullio Cedraschi
Peter T. Harrison[1, 3]
Dr. P. Michael Maher[1, 2]
David J. Sandmeyer

1 Audit Committee
2 Governance & Nominating Committee
3 Reserves Committee

## Officers

William W. Siebens
**Chairman**

David J. Sandmeyer
**President & Chief Executive Officer**

J. Frank George
**Vice-President, Exploitation**

Darren G. Gunderson
**Controller**

Joseph N. Holowisky
**Vice-President Finance & Administration, Chief Financial Officer and Secretary**

William O. Ingram
**Vice-President, Production**

Michael J. Okrusko
**Vice-President, Land**

## Investor Relations Contact

Karen C. Taylor
Manager, Investor Relations
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Freehold

ROYALTY TRUST

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